Greenhouse Gas Emission Trends and Projections for Missouri, 1990-2015 Technical Report

Chapter 3

Projections of CO_2 Emissions from Fossil Fuel Combustion in Missouri's Utility Sector, 1997-2015

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Chapter 3: Estimates of future CO_2 emissions from fossil fuel combustion in Missouri's utility sector

Combustion of fossil fuels to generate electricity is the single largest source of CO_2 emissions in Missouri. In 1996, 48 percent of CO_2 emissions from energy use originated in the utility sector. Changes in the utility sector's use of coal and other fossil fuel resources can dramatically affect the overall level of greenhouse gas emissions in the state, as occurred between 1994 and 1996.

The primary task involved in projecting utility CO_2 emissions is to project the quantity of coal, petroleum and natural gas that will be burned by utilities to generate electricity. The specific mix of fuels is important because coal contains more carbon than petroleum and petroleum contains more carbon than natural gas. Projected CO_2 emissions are estimated from projected fossil fuel consumption using methods similar to those used in the *1990 Inventory* and in Chapter 2.[1]

Part 1 of this chapter projects utility fossil fuel combustion relying on three fairly straightforward "direct" methods, as follows:

- the SS (Steady State) method, which bases its projections on the rate of state population growth;

- the CT-direct (Continuing Trend) method, which bases its projections on simple linear regression from past fossil fuel combustion trends; and

- the AEO-direct (*Annual Energy Outlook*) method, which bases its projections on extrapolation from the *Annual Energy Outlook 1997.*[2]

These three "direct" methods, in addition to their use in Part I of this chapter, are also used in Chapter 4 to project fossil fuel combustion in Missouri's residential, commercial, industrial and transportation sectors. Although the SS method is probably inappropriate for projecting utility generation and fossil fuel use, it is included in this chapter for consistency with the presentation in Chapter 4.

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[1] The primary change in methodology is that the emissions projections in this chapter rely on a single state-specific CO_2 coefficient to estimate statewide CO_2 emissions from coal combustion. The Missouri coefficient is taken from the USDOE/EIA, *State Energy Data Report 1994*, Appendix F. In Chapter 2, CO_2 emissions from utility coal combustion are estimated on a plant-by-plant basis using CO_2 coefficients that are derived for each plant.

[2] USDOE, Energy Information Administration, *Annual Energy Outlook 1997.*

Chart 1 summarizes the utility emissions projections that result from applying these "direct" methods to utility fossil fuel use. In terms developed later in this chapter, the AEO-direct projection is a mid-range projection, and the CT-direct projection is a low-emissions projection.[3]

Chart 1 - Projected CO_2 emissions from the Missouri utility sector, estimated by direct methods, 1990-2015
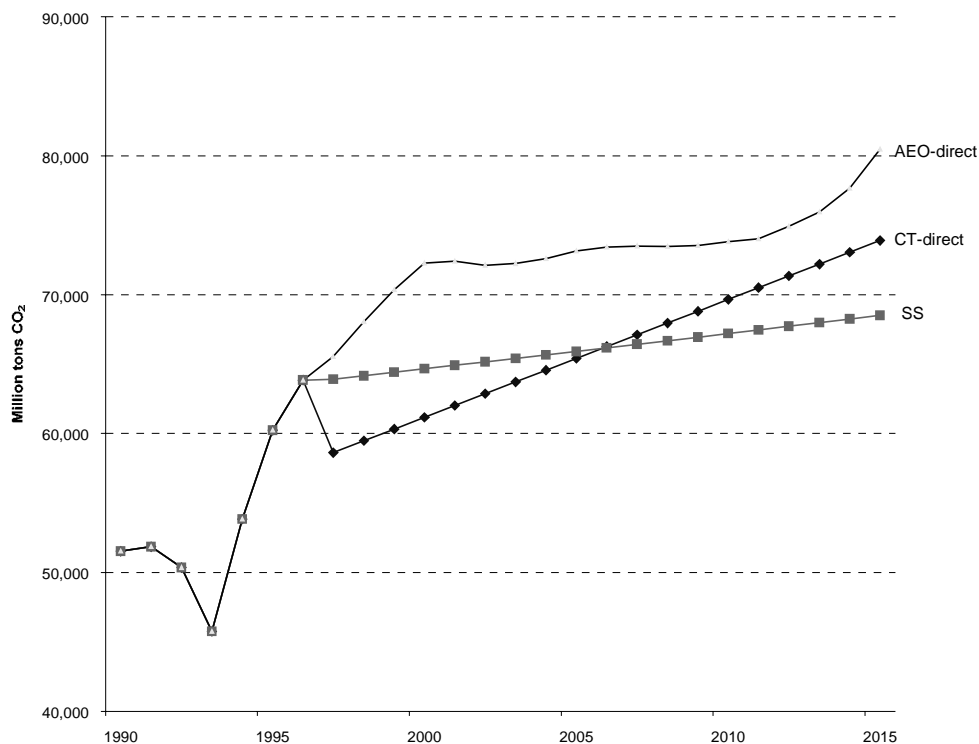
Part 2 of this chapter extends the analysis of utility emissions beyond the relatively simple "direct" estimation methods developed in Part 1. For projections of CO_2 emissions from energy use in the residential, commercial, industrial and transportation sectors, the direct methods were deemed sufficient. However, for utility sector projections, an extension beyond the direct methods was deemed appropriate because (1) electric generation is the single most important source of CO_2 emissions in Missouri and (2) projections are particularly problematic in the utility sector due to uncertainty about the timing and nature of utility restructuring in the state.

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[3] The CT projection in Chart 1 appears to project a reduction in emissions between 1996 and 1997. This is an artifact of the assumption of linearity inherent in simple linear regression. Since short-term trends in utility fossil fuel use are clearly non-linear, the CT-direct method is more usefully viewed as a projection of long-term trend.

Although it is beyond the scope of this study to deal with the full range of uncertainties related to utility restructuring, the extended analysis in Part 2 attempts to incorporate two major factors that are likely to affect future utility CO_2 emissions — (1) projected in-state electricity sales and (2) future utility use of natural gas to generate electricity.

The level of electricity sales is important because CO_2 emissions result from electricity generation, and electricity generation is driven by sales. The level of utility natural gas use is important because natural gas has about 44 percent lower carbon content than coal. It has been estimated that on a full fuel-cycle basis, a highly efficient natural gas-fired turbine produces nearly two-thirds less greenhouse gases than a coal-fired facility.[4]

As Table 1 indicates, the extended analysis in Part 2 of this chapter projects two levels of in-state electricity sales (CT and AEO[5]) and two levels of natural gas use (high and low), resulting in four extended scenarios.

Table 1 - Extended methodology scenarios for Missouri utility CO_2 emissions in 2015

	Low natural gas use (15-30 trillion Btus)	High natural gas use (about 100 trillion Btus)
High (CT) electricity sales (projects 88.5 billion kWh in 2015, based on CT method for projecting in-state electricity sales)	**CT-LowNG** (88.6 million tons CO_2 in 2015, a 2.2% growth rate between 1990-2015)	**CT-HighNG** (82.1 million tons CO_2 in 2015, a 1.9% growth rate between 1990-2015)
Low (AEO) electricity sales (projects 81.5 billion kWh in 2015, based on AEO method for projecting in-state electricity sales)	**AEO-LowNG** (80.9 million tons CO_2 in 2015, a 1.8% growth rate between 1990-2015)	**AEO-HighNG** (73.9 million tons CO_2 in 2015, a 1.5% growth rate between 1990-2015)

The CO_2 projections in Table 1 can be divided into high, midrange and low estimates:

- The CT-LowNG scenario projects a level of emissions substantially higher than any projected using the direct methods. According to this scenario, utility CO_2 emissions in 2015 will be 72 percent higher than utility emissions in 1990.

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[4] M.A. Deluchi, *Emissions of Greenhouse Gases for the Use of Transportation Fuels and Electricity*, Volume 1, Argonne National Laboratory, p. 54.

[5] So named because linear regression (CT) methods project relatively high electricity sales whereas extrapolation from the *Annual Energy Outlook 1997* (AEO) results in a lower projection of electricity sales.

- The CT-HighNG and AEO-LowNG scenarios project emissions in the same middle range as the AEO-direct projection. According to this scenario, utility CO_2 emissions in 2015 will be approximately 56 to 59 percent higher than in 1990.

- The AEO-HighNG scenario projects a relatively low level of emissions in the same range as the CT-direct projection. According to this scenario, utility CO_2 emissions in 2015 will be 43 to 44 percent higher than in 1990.

Charts 2 and 3 illustrate the clustering of these projections into high-, midrange- and low-CO_2 estimates.[6] Chart 2 illustrates the CO_2 emissions projected by the four extended scenarios. Chart 3 is similar, but includes the AEO-direct and CT-direct projections.

It should be noted that "low emissions" is a relative term, since the "low" projections are for a very substantial 43 to 44 percent increase in utility emissions over 1990 levels.

Chart 2 - Projected CO₂ emissions from the Missouri utility sector, estimated by extended methodology, 1990-2015

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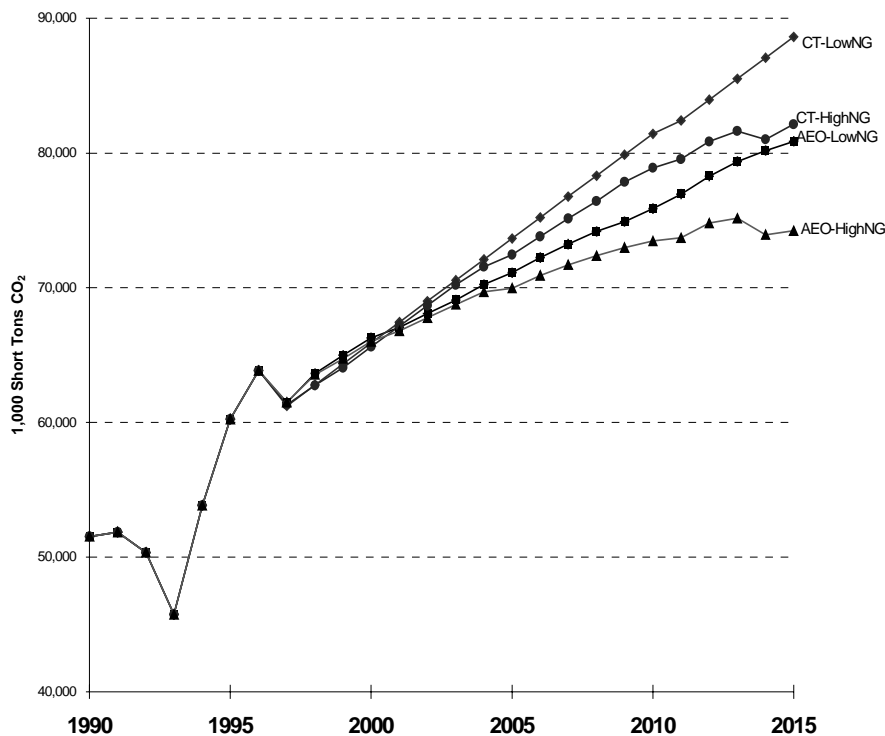
[6] Chart 3 also illustrates the SS projection, which is lower than the "low-emissions" projections discussed in the text. As noted above, the SS projection method is probably inappropriate for utility emissions but is included for completeness.

Chart 3 - Projected CO_2 emissions from the Missouri utility sector, estimated by direct and extended methodologies, 1990-2015
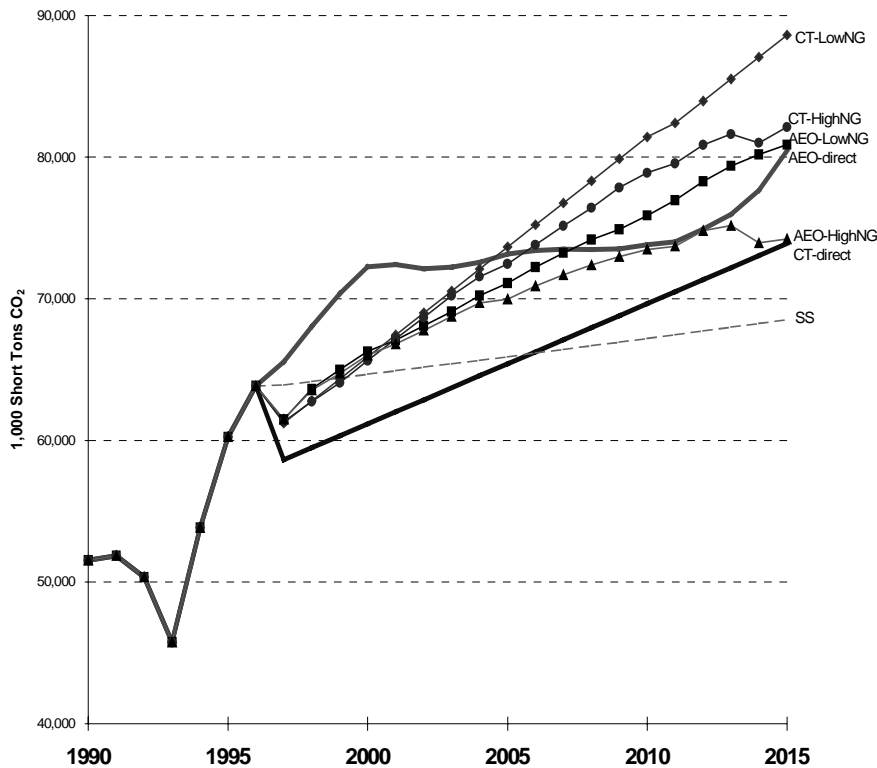
The four extended scenarios are not intended to be exhaustive. Many factors not explicitly incorporated in Table 1 could influence in-state electricity generation and CO_2 emissions.[7]

(1) Future utility sales and energy input choices could be affected by state or federal restructuring policy decisions, such as requirements to include renewable energy in the mix of energy sources used to generate electricity ("portfolio requirements") or legislation creating new funding sources for demand-side management programs.

(2) Variation in demographic factors, economic growth or the rate of technological innovation could lead to in-state sales that are higher or lower than those used in the extended scenarios.

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[7] Factors considered in the risk analysis portions of the AmerenUE and Kansas City Power and Light (KCPL) Integrated Resource Plans are representative. AmerenUE, *Energy Resource Plan*, June 1995, p. 15; Kansas City Power and Light (KCPL*), KCPlan 94: Integrated Resource Plan (1995-2014*), Volume 1: Summary.

In both the U.S. and Missouri, electricity sales have steadily increased since the 1960s, but the average annual rate of increase has slowed over time. The extended scenarios assume the average annual rate will either remain steady (CT-sales scenarios) or continue to decrease (AEO-sales scenarios).

The high-sales (CT-sales) scenarios in Table 1 project 88.5 billion kilowatt-hours (kWh) of in-state electricity sales in 2015. These scenarios assume that sales to end users in Missouri's residential, commercial and industrial sectors will continue to follow 1984 to 1996 trends. These scenarios project an average annual growth rate through 2015 of about 1.8 percent per year, slightly below the projected 1.9 percent growth rate for gross state product.

The low-sales (AEO-sales) scenarios in Table 1 project 81.5 billion kilowatt-hours (kWh) of in-state electricity sales in 2015. This scenario is derived from the EIA's *Annual Energy Outlook 1997* projections for residential, commercial and industrial electricity sales in the North West Central census region and reflects the *Annual Energy Outlook's* assumption that future growth in electricity sales will slow to levels below the 1984 to 1996 trend. Part 2, Section 1 discusses EIA's reasoning for this assumption.

The low-sales scenarios project an average annual growth rate through 2015 of about 1.36 percent per year. This is lower than the *Annual Energy Outlook's* projections for national electricity sales (1.44 percent) and regional electricity sales (1.64 percent). The rate is below national and regional projections because Missouri population growth is expected to be slower than national and regional population growth.[8]

Both the high-sales and low-sales estimates may be conservative. Some Missouri utilities assume higher sales growth than those used in these scenarios.

For example, Springfield City Utilities, the municipal utility with the greatest generating capacity in Missouri, currently assumes that over its planning horizon electricity sales will grow at about 3 percent per year, with about 1.7 percent due to an increasing consumer base and 1.3 percent due to increased sales per consumer.[9]

AmerenUE and Kansas City Power and Light (KCPL), the two largest investor-owned utilities in Missouri, account for about 57 percent of in-state sales to electricity end users.[10]

In its 1994 and 1995 Integrated Resource Plans (IRPs), AmerenUE forecasted annual sales growth of 1.8 percent through 2005, and KCPL forecasted annual sales growth of 2.3 percent through 2015.[11]

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[8] Some utility planners assume higher sales growth than those used in these scenarios. For example, the Springfield municipal utility currently assumes that its electricity sales will grow at about 3 percent per year.

[9] Personal communication, Cathy Meyer, Manager-Rates & Fuels, 06/17/97.

[10] This estimate is based on analysis of utility-level USDOE/EIA data compiled from reports submitted by Missouri utilities using Form EIA861.

[11] Union Electric (UE), now AmerenUE, *Energy Resource Plan*, June 1995, p. 15; Kansas City Power and Light (KCPL*), KCPlan 94: Integrated Resource Plan (1995-2014)*, Volume 1: Summary, p. III-4.

(3) Technological, economic and institutional factors could lead to utility levels of natural gas that are higher or lower than those used in the scenarios.

Over time, the rate of increase in Missouri utility electricity sales will determine how much additional base load power must be generated or otherwise acquired to meet increased demand.[12] At present, base load generation of electricity from coal-fired boilers accounts for about 99 percent of utility CO_2 emissions. Generating capacity sets an upper limit on CO_2 emissions from coal. Part 2, Section 3, estimates that Missouri utilities could generate up to 85 million tons of CO_2 per annum from coal-fired boilers at present.

In the intermediate to long run, the upper limit on CO_2 emissions may increase or decrease as utilities choose to construct new plants or repower existing plants. The scenarios in Part 2 are constructed assuming the primary candidates for additional intermediate or base load generation are coal- or natural gas-based generation technologies.[13]

Currently, Missouri utilities use natural gas primarily to meet peak load demands. As described in Part 1, Section 2, the high and low natural gas scenarios in Table 1 are both based on *Annual Energy Outlook 1997* projections, but use different methods to extrapolate from these projections. The *Annual Energy Outlook 1997* anticipates an expanded role for natural gas over the next 20 years.

The high natural gas scenarios anticipate that Missouri utilities will follow national trends and use natural gas as an energy source for generating intermediate and base load power, displacing some coal use. The low natural gas scenarios, in contrast, assume that Missouri utilities will increase their use of natural gas to meet peak load requirements and will build some intermediate generating capacity, but will not add significant natural gas base load generating capacity.

Under the low natural gas scenarios, Missouri utilities will continue to rely primarily on coal. The CT-LowNG scenario projects that new coal-fired capacity will be required and built after 2011, whereas the AEO-LowNG scenario projects that requirements for coal-fired generation can be met by the state's current coal-fired capacity. Total CO_2 emissions under the these two scenarios are about 6 to 6.5 million tons higher than CO_2 emissions from the corresponding scenarios that assume base generation from natural gas.

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[12] Demand-side management (DSM) is an alternative to generation or purchase and is treated as such in the AmerenUE and KCPL Integrated Resource Plans. However, a number of Missouri utilities appear to view DSM primarily as a means to reduce peak load rather than base load. Because the current analysis is intended to serve as a business-as-usual projection, it is assumed that DSM programs are maintained but not expanded.

[13] In a latter phase of the project, the analysis will be extended to incorporate renewable sources and fuel cells. The present analysis is focused on supply-side generation sources for which utilities have shown a current preference and for which there are data on past utility consumption. The AmerenUE and KCPL Integrated Resource Plans cited in Footnote 29 considered many supply-side options, but the preferred options were generally for constructing or repowering coal- and natural gas-fired units.

However, the level of Missouri natural gas use could fall outside the range of the scenarios in Table 1 for two reasons:

- *Annual Energy Outlook* projections of regional utility natural gas use are based on assessment of many economic and technological factors. However, the regional projections are subject to a high level of uncertainty. Technological and economic factors may influence the price, availability and relative attractiveness of natural gas and natural gas-based generating technologies, leading to higher or lower levels of natural gas use than those incorporated in the scenarios.

- Extrapolation from regional projections does take into account state or institutional factors that may influence utility decisions on construction and utilization of natural gas generating facilities. Past Missouri utility decisions have indicated a preference for purchasing power rather than building new natural gas generating capacity. Under restructuring, the availability of purchased power may increase or decrease.

(4) Table 1 does not incorporate possible changes in the level and balance of export sales and purchases from outside Missouri. All four scenarios assume that Missouri will continue to be a net exporter of electricity and that exports will continue to be small in proportion to in-state sales. Under a restructured market, it is possible that net exports could change significantly. A large increase in net exports could lead to an increase in coal-fired generation and larger increases in CO_2 emissions than projected in this chapter. An increase in net imports would probably reduce future CO_2 emissions from projections.

Even under the current regulated environment, wholesale power sales purchases have been an important aspect of utility planning. If restructuring occurs, there may be major shifts in the customer base of Missouri utilities. A logical next research step would be to formulate scenarios that explicitly incorporate possible shifts in electricity exports and imports, and to assign probabilities and CO_2 "payoffs" to each scenario. These were not incorporated into the current report due to lack of sufficient data.

Part 1: Direct estimates of future utility fossil fuel use and CO_2 emissions

Three different methods were used to directly estimate future use and CO_2 emissions from utility use of petroleum, natural gas and coal:

- the "Steady State" (SS) method, which assumes that fuel use increases at the rate of population growth;

- the "Continuing Trend" (CT) method, which projects future use through regression analysis of past trends;

- the "*Annual Energy Outlook*" method, which extrapolates from regional estimates in the *Annual Energy Outlook 1997* (AEO), adjusted to take into account the projected rate of state population growth relative to regional population growth.

The petroleum and natural gas estimates were used as input into the model developed in Part 2, and the coal estimate was used as a reference point for the estimates of coal consumption developed in Part 2.

Section 1: Projected CO_2 emissions from utility petroleum use

In 1996, Missouri utilities operated petroleum-fired generating facilities with a summer capability of 1,710 megawatts. The *Inventory of Power Plants in the United States* reports 452 megawatts of planned additions burning petroleum; however, with the exception of several small internal combustion units planned by municipalities, most of the units listed in the Inventory are dual-fired units that will primarily burn natural gas.[14]

Petroleum's principal role is to provide peak load power or a backup fuel for dual-fired units. Missouri utility use of distillate and residual fuel peaked in 1978 at 16 trillion Btus and during 1990 averaged 1 to 2 trillion Btus.

Table 2 and Chart 4 present estimates from the SS, CT and AEO methods. All three methods project that utility petroleum consumption will remain below 3 trillion Btus through 2015 and that CO_2 emissions will remain below 0.25 million tons.

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[14] USDOE/EIA, *Inventory of Power Plants in the United States as of January 1, 1996*, Table 17; personal communication, Dan Beck, Missouri Public Service Commission, 06/03/97.

Table 2 - Projected CO$_2$ emissions from Missouri utilities' use of petroleum to generate electricity, by direct projection method

Units: 1,000 Short Tons Carbon Dioxide (CO$_2$)

	1990	1995	2000	2005	2010	2015
Steady State	93	138	118	121	123	125
Continuing Trend	93	138	107	96	85	74
AEO	93	138	56	56	127	211

Chart 4 - Steady State (SS), Continuing Trend (CT) and AEO direct projections of utility CO$_2$ emissions from combustion of petroleum
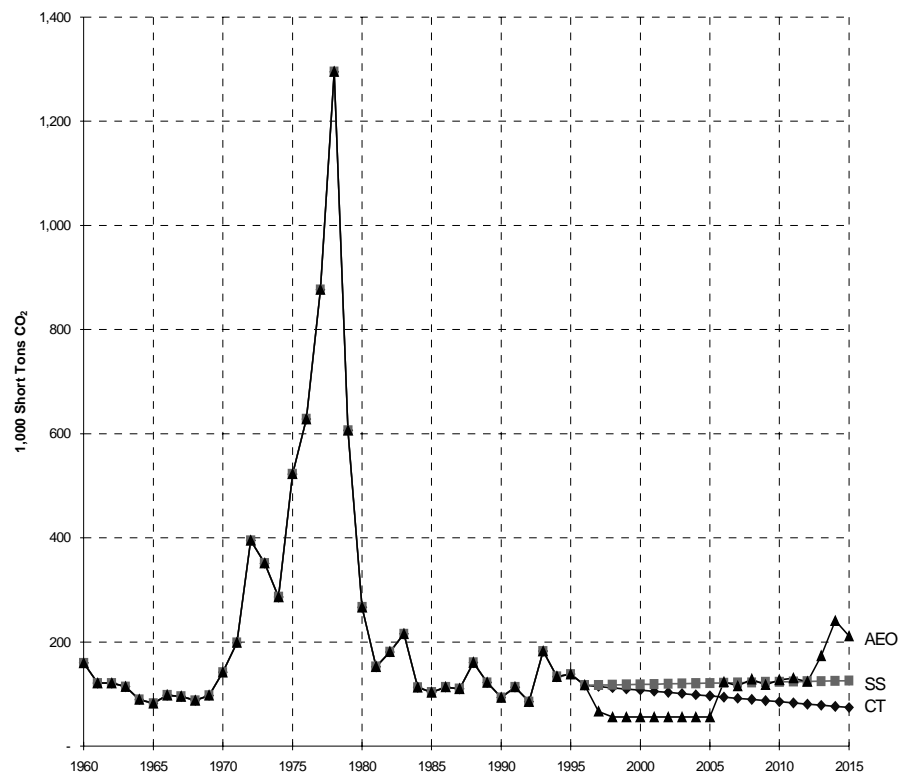
Section 2: Projected CO_2 emissions from utility natural gas use

In 1996, Missouri utilities operated natural gas-fired generating facilities with a summer capability of 1,205 megawatts, with planned additions scheduled for more than 2,000 megawatts including dual-fired units.[15] As Chart 5 illustrates, utility natural gas consumption peaked in 1971 at about 68 trillion Btus and has exceeded 10 trillion Btus only twice since 1980.

As Chart 5 illustrates, the SS and CT methods project only a small increase in utility natural gas use. The chart provides two separate AEO projections, both of which are substantially larger than the SS and CT projections. Given utility plans to more than double capacity, the AEO projection is much more credible than those from the other two methods. By their nature, the SS and CT methods take only current or past utility fuel use into account and cannot incorporate structural changes in energy use.

Chart 5 - Estimated utility natural gas use, 1960-2015

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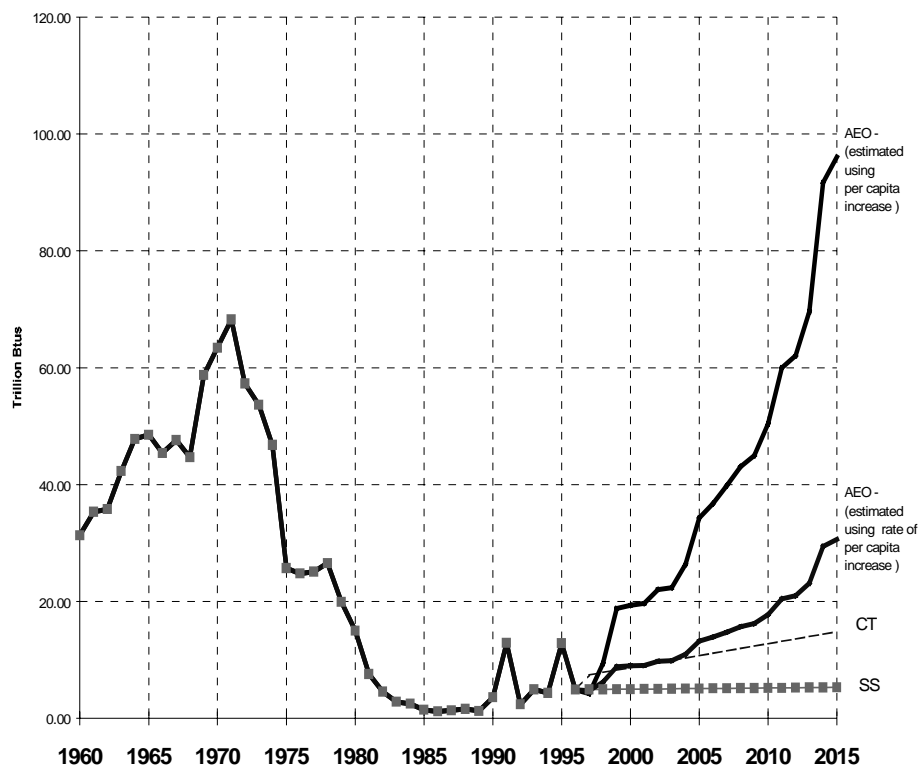
[15] USDOE/EIA, *Inventory of Power Plants in the United States as of January 1, 1996*, Table 17.

Both AEO projections in Chart 5 are based on the *Annual Energy Outlook 1997* projection for utility natural gas use in the West North Central region. Both are adjusted to account for Missouri's lower rate of population growth.

The lower AEO projection for Missouri utility natural gas use in 2015 was estimated by assuming that per capita natural gas use of Missouri utilities will increase at the same rate as per capita use in the rest of the region. The resulting projection, 30.6 trillion Btus in 2015, represents an annual growth rate of about 10.1 percent, comparable to the 10.5 percent growth rate that AEO projects for the region as a whole.

However, the *Annual Energy Outlook 1997* estimates that utility consumption of natural gas in the North West Central region as a whole will increase by 380 trillion Btus, from about 60 trillion Btus in 1995 to more than 400 trillion Btus in 2015. The lower projection implies that less than 10 percent of this expansion will occur in Missouri.

The higher AEO projection was estimated by assuming that Missouri per capita use will increase by the same amount as per capita use in the rest of the region. It implies that about 30 percent of the region's expansion in natural gas use will occur in Missouri, about the same as Missouri's share of total utility sales in the region.

One justification for considering both a low and high AEO projection is that a fairly large degree of uncertainty is associated with projections of utility natural gas use. In the 1997 edition of the *Annual Energy Outlook*, EIA's reference case projections for utility natural gas use in 2015 were higher than the projections by three other major forecasting sources.[16] A year later, EIA's projections had not changed much, but the revised projections by two of the other three forecasting sources were higher than the projections in the 1998 edition of *Annual Energy Outlook*.

A second justification is that the projection must be based on the outcome of future decisions by Missouri utilities. The lower projection represents a decision to continue using natural gas primarily to provide peak load requirements. The higher projection represents a decision to use natural gas to provide intermediate and base-load, as well as peak-load, power.

Utility decisions will be influenced by a variety of factors that will reinforce or disrupt the status quo. In addition to fuel price, these include sales demand, technological change and political decisions such as restructuring and environmental regulation.

The USDOE/EIA National Energy Modeling System (NEMS) model used to develop the *Annual Energy Outlook 1997* projections includes a linear optimization module for projecting technology choices in the utility sector. The NEMS model projects that new natural gas facilities will outnumber new coal steam plants by a 4-to-1 margin. This would include widespread addition of natural gas combined-cycle turbines suitable for midrange and base-load generation. Factors favoring such a decision include relatively low capital requirements, short construction lead times and high conversion efficiency of natural gas turbines and combined-cycle technology.[17]

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[16] *Annual Energy Outlook 1997*, Table 20, p. 80, and Table F8, p. 190; and personal communication, David Shoeberlein, USDOE/EIA, 06/23/97.

[17] *Annual Energy Outlook 1997*, p. 49; personal communication, David Shoeberlein, USDOE/EIA, 06/17/97.

Similarly, a recent USEPA analysis projects that new generating facilities will be based on natural gas rather than coal.[18] The USEPA analysis projects that electric generation in the U.S. will continue to grow over the next 15 years, that low-cost coal-fired units will improve their capacity and have greater accessibility to potential customers by 2000, and that most increases in generation through 2010 will be supplied by coal-fired electric generation units.

However, USEPA also projects that the increase in generation by coal-fired units after 2000 will occur through their increased use of existing capacity as they gradually increase their output to keep pace with demand, and that no new coal-fired units will be built after 2000. Instead, from 2000 to 2010, improvements in combined-cycle technology and relatively low natural gas prices will lead the power industry to substantially increase its gas combined-cycle capacity. The capacity increases would come from construction of new gas combined-cycle as well as the repowering of some existing oil/gas steam units as combined-cycle gas units.

Missouri utilities' preference for natural gas could also be influenced by a recent USEPA rule intended to reduce nitrogen oxides (NO_x) emissions in Missouri and several other states. In September, 1998, USEPA announced a final rule setting summer season[19] NO_x budgets for Missouri, 21 other states and the District of Columbia and requiring state implementation plans (SIPs) to meet these budgets. Missouri and the other states must submit their plans by September 1999 and implement them by May 1, 2003.

In late Spring, 1998 the U.S. Court of Appeals for the District of Columbia Circuit granted a motion for partial stay of USEPA's rule until April 2000. The following discussion addresses the likely impact if the USEPA rule is eventually implemented.

The purpose of this rule, commonly known as the NO_x SIP call, is to reduce regional transport of ground-level ozone that currently affects several northeastern states.[20] Although the NO_x SIP call does not officially mandate the content of the state implementation plans, USEPA analyses, and model plans leading to the SIP call, have presumed that state plans will focus on reducing NO_x emissions from utilities and other major point sources.[21]

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[18] USEPA, Analyzing Electric Power Generation Under the CAAA. This study and other documents based on USEPA's use of the Integrated Planning Model (IPM) may be found at USEPA's IPM site, http//www.epa.gov/capi/otagmain. html. USEPA adopted IPM in 1995 as the basis for baseline and policy analysis of electric generation and emissions. IPM was developed by ICF Resources, a consulting firm.

[19] Summer season is the period May 1 through September 30.

[20] The action arose because the difficulty experienced by several northeastern states in meeting the ground-level ozone requirements of the Clean Air Act was attributed to NO_x emissions originating in other states, including Missouri. NO_x reacts in the atmosphere to form compounds that contribute to the formation of ozone. These compounds, as well as ozone itself, can travel hundreds of miles across State boundaries to areas such as the eastern U.S. that are far from the source of the pollution.

[21] USEPA's announcement of the final rule in September, 1998 was preceded by two years of discussion of the ozone transport issue within the Ozone Transport Assessment Group (OTAG), a partnership with the 37 easternmost States and the District of Columbia, industry representatives, and environmental groups. In June 1997, the OTAG states voted 32-5 in favor of a strategy to reduce NO_x emissions from utilities and other major point sources. In November, 1997, after a review of OTAG's analysis, findings, and recommendations, USEPA proposed a rule to limit summer season NO_x emissions with specific budgets for each state to be included in the rule. USEPA subsequently developed a NO_x Model Cap and Trade Rule to provide an emissions trading framework within the ozone transport rulemaking.

Utility compliance with the rule might result in greater use of natural gas than would otherwise occur. Of the many options for complying with the rule, several would tend to result in substitution of natural gas for coal consumption. Two options would directly increase natural gas: (1) repowering coal plants — for example, converting them to natural gas combined cycle plants; and (2) retiring them and replacing them with combined cycle plants. This would lead to year-round increases in natural gas use.

In addition, natural gas use could increase if utility dispatch decisions during summer months change to favor low-NO_x sources of power. However, changing dispatch rules would lead to a significant increase in natural gas use only if there are relatively low natural gas prices and if a number of recent-technology natural gas plants such as combined cycle plants have already been built. Natural gas-fired generation would have to compete with other low-NO_x sources such as nuclear plants, hydroelectric generation and wholesale purchase. Some coal plants — including certain coal plants in Missouri — are also low NO_x emitters and would be favored, but many older coal plants tend to be high NO_x emitters and would be less used.

However, the impact of the rule on natural gas use will probably be minor because, according to USEPA impact analysis of the NO_x SIP call, utilities will probably comply with the rule primarily by placing controls on coal plants rather repowering them or shutting them down. USEPA projects that "almost all of the coal-fired capacity is retrofitted with some NO_x control equipment under the Proposed Regulatory Approach. However, most of the oil and gas steam units are not retrofitted with control technology [and] no existing combined-cycle units are forecast to add pollution controls." [22] The rule would be most likely to lead to a coal plant's retirement if the plant is marginally profitable and if the utility anticipates that the plant will require an additional investment in carbon emissions controls in the future.

The factors tending to increase Missouri utilities' natural gas use must be weighed against certain factors that could limit Missouri utilities' reliance on natural gas. These factors include the following: (1) the preference of some Missouri natural gas utilities that natural gas, as a premier fuel, be used for purposes other than utility power generation[23]; (2) possible limits on pipeline capacity; and (3) the price impact of increased demand for natural gas.

USEPA, like EIA, relies on NEMS for "base case" projections of natural gas prices. The NEMS base case assumes that natural gas prices will remain fairly stable through 2015 as the result of new technology for natural gas exploration and recovery. In the alternative "low technology" case, supply limitations are expected to put upward pressure on natural gas prices, which would result in a shift of a large portion of new utility construction from natural gas to coal.

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[22] USEPA, April 1998, Chapter 2, *Electric Power Industry*, p. 2-18.

[23] Reviewer comment by Omar Yaakub, Laclede Natural Gas, 6/98.

In their capacity planning process, Missouri utilities have given favorable consideration to combined-cycle units or other natural gas technologies suitable for intermediate and base-load generation. However, no large Missouri utility has built or announced plans to build such units, partly because of favorable wholesale purchase opportunities and partly because of the uncertainties over future natural gas supply and prices described above.[24]

The estimates of utility CO_2 emissions from natural gas use presented in Table 3 and Chart 6 include both the low and high AEO projections. The expansion of natural gas extrapolated from AEO projections would imply 5.6 million tons of CO_2 emissions at the higher level of use and 1.8 trillion tons at the lower level of use.

Table 3 - Projected CO₂ emissions from Missouri utilities' use of natural gas to generate electricity, by direct projection method

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1996	2000	2005	2010	2015
Steady State	207	284	290	296	302	308
Continuing Trend	207	284	505	624	743	862
AEO - HighNG use	207	284	1,126	1,995	2,931	5,589
AEO - LowNG use	207	284	523	768	1,032	1,781

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[24] On more than one occasion, regulated utilities undergoing the IRP process have considered construction of an advanced natural gas facility but have preferred to pursue wholesale purchase contracts for the power the facility would have provided. However, KCPL has operated a recently added natural gas unit at about 25 percent capacity — higher than normal use of a peak-load facility — because it has found it is economical to do so. Personal communication, Dan Beck, Missouri Public Service Commission, 06/03/97.

Chart 6 - Steady State (SS), Continuing Trend (CT) and AEO direct projections of utility CO$_2$ emissions from combustion of natural gas

Section 3: Projected CO_2 emissions from utility coal use

In 1996, Missouri utilities operated coal-fired generating facilities with a summer capability of 10,575 megawatts. No additional coal-fired units are planned at this time.[25] Utility coal consumption in Missouri reached a peak of about 550 trillion Btus in 1984, dropped by about 80 trillion Btus after the Hallway nuclear power plant came on line in 1984-86, and recently increased to record consumption of about 570 trillion Btus in 1995 and 602 trillion Btus in 1996. Chart 7 illustrates the pattern of utility coal use through 1996.

Chart 7 - Missouri utility coal use, 1960-96

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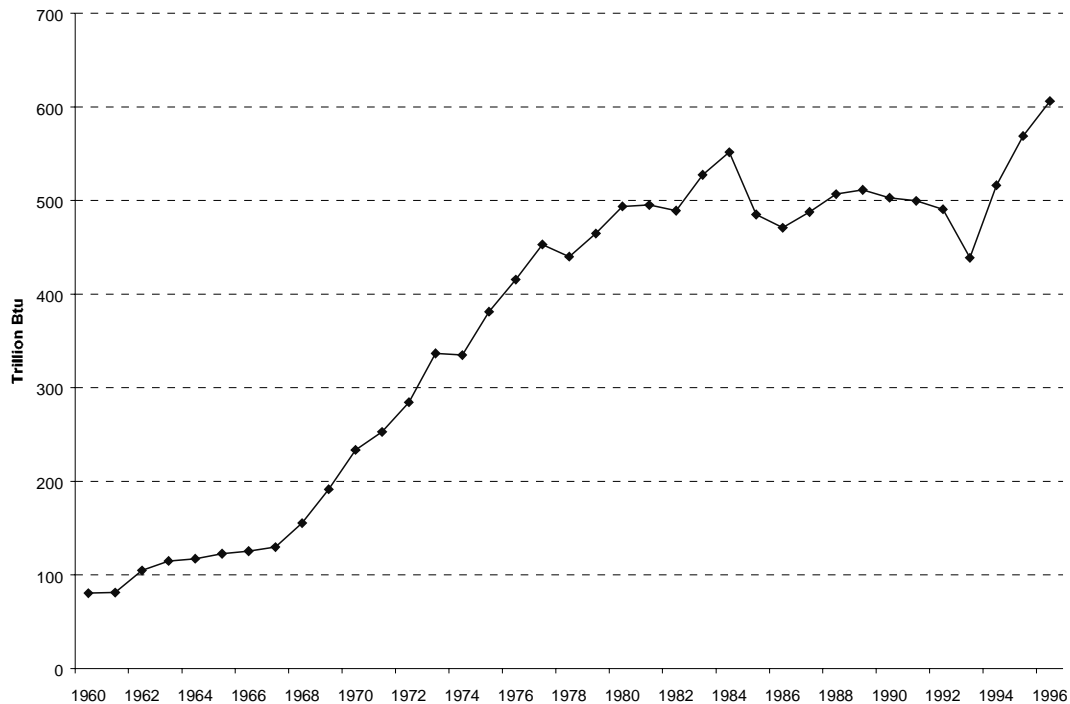
[25] USDOE/EIA, *Inventory of Power Plants in the United States as of January 1, 1996*, Table 17.

Part 2 of this chapter focuses on estimating utility coal consumption and CO_2 emissions based on projections of electricity sales. However, the SS, CT and AEO methods were also applied to directly estimate future coal consumption without reference to electricity sales. The resulting projections were spread from a low projection of about 650 trillion Btus (SS method) to a high projection of about 750 trillion Btus (AEO method).

The previous discussion of natural gas describes two methods for extrapolating AEO regional projections to Missouri. Although the two methods result in divergent projections for utility natural gas use, they are in fairly close agreement on future coal use. If Missouri per capita coal use increases at the same rate as per capita use in the rest of the region, the resulting projection is for 768 trillion Btus, a 1.3 percent growth rate. If it increases by the same amount as per capita use in the rest of the region, the resulting projection is for 753 trillion Btus, a 1.1 percent growth rate. The latter method is used for coal and the other fuel projections in this report.

Table 4 summarizes the projections of CO_2 emissions resulting from the three methods for directly estimating utility coal use. Chart 1 in the introduction to this chapter provides graphic illustration of the three direct estimates of utility CO_2 emissions from coal.
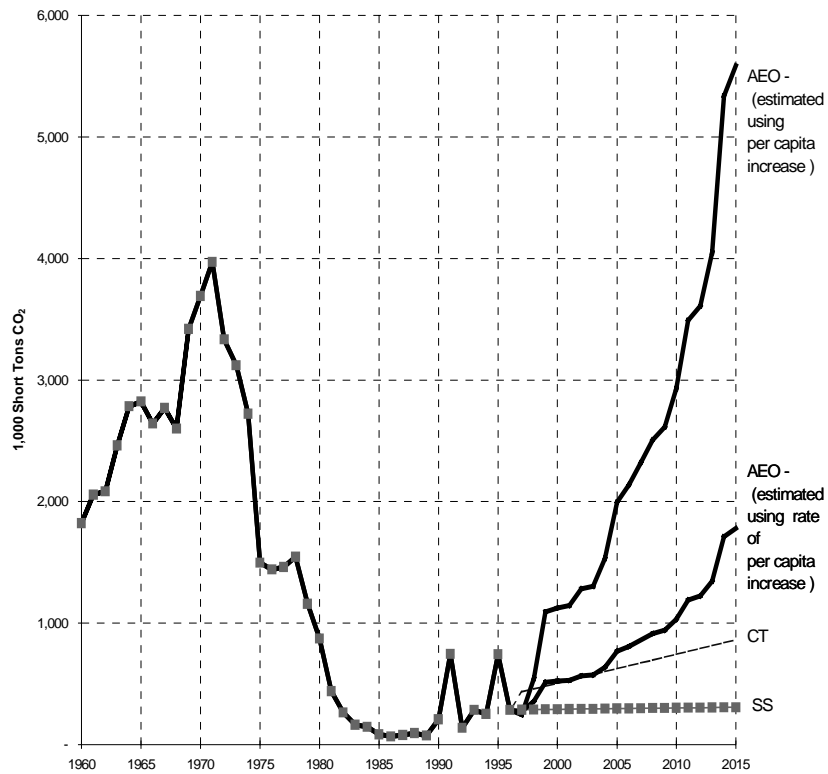

Table 4 - Projected CO_2 emissions from Missouri utilities' use of coal to generate electricity, by direct projection method

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	1995	2000	2005	2010	2015
Steady State	51,238	59,362	64,255	65,493	66,771	68,083
Continuing Trend	51,238	59,362	60,561	64,693	68,825	72,957
AEO	51,238	59,362	71,730	72,378	72,751	78,584

Part 2: Projections of utility fossil fuel use and CO_2 emissions based on extended analysis of future electricity sales and natural gas use

The introduction to this chapter introduced the extended analysis of utility CO_2 emissions based on two primary factors: future utility natural gas use and future electricity sales. Two possible levels of natural gas use were estimated in Part 1, Section 2. Part 2, Sections 1 and 2 of this chapter estimate future in-state sales and discuss export sales.

Following these assessments of the two primary factors of the extended analysis, Section 4 develops the analytic model to be used — a simple spreadsheet accounting model used to specify the interaction of factors likely to affect future utility CO_2 emissions. Section 5 presents the model's base-case projections for the four scenarios, and Section 6 presents representative results of sensitivity analysis of assumptions used in developing the scenarios.

The model uses a sales-and-sources accounting approach to estimate CO_2 emissions. The energy sources included in the model are coal, natural gas, petroleum, nuclear and hydroelectric generation.[26] The model assumes net sales equal total power generated and depends on several variables that must be supplied from outside the model. These exogenous variables include in-state electricity sales; annual consumption of all energy resources except coal; average heat rates for generating technologies; and the distribution of an energy resource such as natural gas across generating technologies such as gas turbine or combined cycle.

Given an assumed level of sales, the model calculates the coal-fired generation required to balance electricity generation and sales and estimates the resulting CO_2 emissions from coal and other energy resources. Table 5 summarizes the methods used to model the four scenarios and compares them to the CT and AEO direct estimates in Section 1.

For its standard case, the analysis assumes that gross state product (GSP) will grow at an annual rate of 1.9 percent, identical to that used in the *Annual Energy Outlook 1997* reference case. When comparing high- and low-growth cases to the standard case, the study adopts the *Annual Energy Outlook 1997* estimates of rapid (2.4 percent), moderate (1.9 percent) and slow (1.4 percent) economic growth.[27] The analysis uses 1987 dollars to compare GSP and GNP projections. Projections of Missouri population growth are based on the State Demographer's zero-migration case projection, adjusted by addition for actual 1995 values.

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[26] In a latter phase of the project, the model will be extended to include renewable resources such as wind, solar and biomass.

[27] *Annual Energy Outlook 1997*, Table 13, p. 76, cites an identical moderate growth forecast from consulting firm DRI. By comparison, consulting firm WEFA forecasts a higher 2.2 percent rate of growth for GNP. The University of Missouri-Columbia Business and Public Administration Research Center projects a 2.315 percent growth rate for Missouri GSP through 2015, which corresponds to the WEFA forecast and the AEO/DRI rapid-growth case. Personal communication, Deenie Neff, UMC BandPA Research Center, 05/29/97.

Table 5 - Comparison of methods used to estimate future utility CO_2 emissions from fossil fuel combustion

	CT direct estimate	CT sales scenario-low natural gas use	CT sales scenario-high natural gas use	AEO direct estimate	AEO sales scenario-low natural gas use	AEO sales scenario-high natural gas use
Electricity sales	N/A	Aggregated from trend analysis of past residential, commercial and industrial use; three cases based on starting year for trend analysis (1960-1994, 1970-1994 or 1980-1994)	Aggregated from trend analysis of past residential, commercial and industrial use; three cases based on starting year for trend analysis (1960-1994, 1970-1994 or 1980-1994)	N/A	Residential/commercial sales are assumed to grow at same rate as AEO sales per capita. Industrial sales are assumed to grow at same rate as AEO sales per unit of GNP, with three cases based on growth rate of GSP.	Residential/commercial sales are assumed to grow at same rate as AEO sales per capita. Industrial sales are assumed to grow at same rate as AEO sales per unit of GNP, with three cases based on growth rate of GSP.
Utility coal consumption	Based on trend analysis of past utility coal consumption	Based on heat rate and: 1) CT estimate of electricity sales, 2) estimated generation from natural gas based on CT estimate of natural gas use, and 3) CT estimates of megawatt-hour generation from other sources	Based on heat rate and: 1) CT estimate of electricity sales, 2) estimated generation from natural gas based on AEO high estimate of natural gas use, and 3) CT estimates of mWh generation from other sources	Based on AEO97 projections of utility coal use per capita	Based on heat rate and: 1) AEO estimate of electricity sales, 2) estimated generation from natural gas based on AEO low estimate of natural gas use, and 3) AEO estimates of mWh generation from other sources	Based on heat rate and: 1) AEO estimate of electricity sales, 2) estimated generation from natural gas based on AEO high estimate of natural gas use, and 3) AEO estimates of mWh generation from other sources
Utility natural gas consumption	Based on trend analysis of past utility natural gas consumption	Based on trend analysis of past utility natural gas consumption	Based on AEO97 projections of utility natural gas use per capita	Based on AEO97 projections of utility natural gas use per capita	Based on AEO97 projections of utility natural gas use per capita	Based on AEO97 projections of utility natural gas use per capita
MWh generation from natural gas	N/A	Based on natural gas consumption and heat rate distributed across technologies	Based on natural gas consumption and heat rate distributed across technologies	N/A	Based on natural gas consumption and heat rate distributed across technologies	Based on natural gas consumption and heat rate distributed across technologies
Utility petroleum consumption	Based on trend analysis of past utility petroleum consumption	Based on trend analysis of past utility petroleum consumption	Based on trend analysis of past utility petroleum consumption	Based on AEO97 projections of utility petroleum use per capita	Based on AEO97 projections of utility petroleum use per capita	Based on AEO97 projections of utility petroleum use per capita
MWh generation from petroleum	N/A	Based on petroleum consumption and heat rate	Based on petroleum consumption and heat rate	N/A	Based on petroleum consumption and heat rate	Based on petroleum consumption and heat rate

Section 1: Estimates of future in-state electricity sales

In-state electricity sales are estimated using methods based on the CT, AEO and SS approaches introduced in Section 1. Sales are projected for the three major electricity end-use sectors — residential, commercial and industrial — and aggregated into a projection of total in-state sales.

All three sales projections are pictured in Chart 8. The SS estimate, which assumes that future residential and commercial sales will grow at the rate of state population and that industrial demand will grow at the rate of GSP, projects very slow growth in residential sales (26 percent over baseline) and commercial sales (19 percent) and very rapid growth (87 percent) in industrial sales of electricity. The SS sales projections are probably not realistic and are not used as the basis for developing extended scenarios of future CO_2 emissions. However, they are presented for comparison with the CT and AEO projections.

Chart 8 - Comparison of CT, AEO and SS projections of aggregate electricity sales growth in Missouri
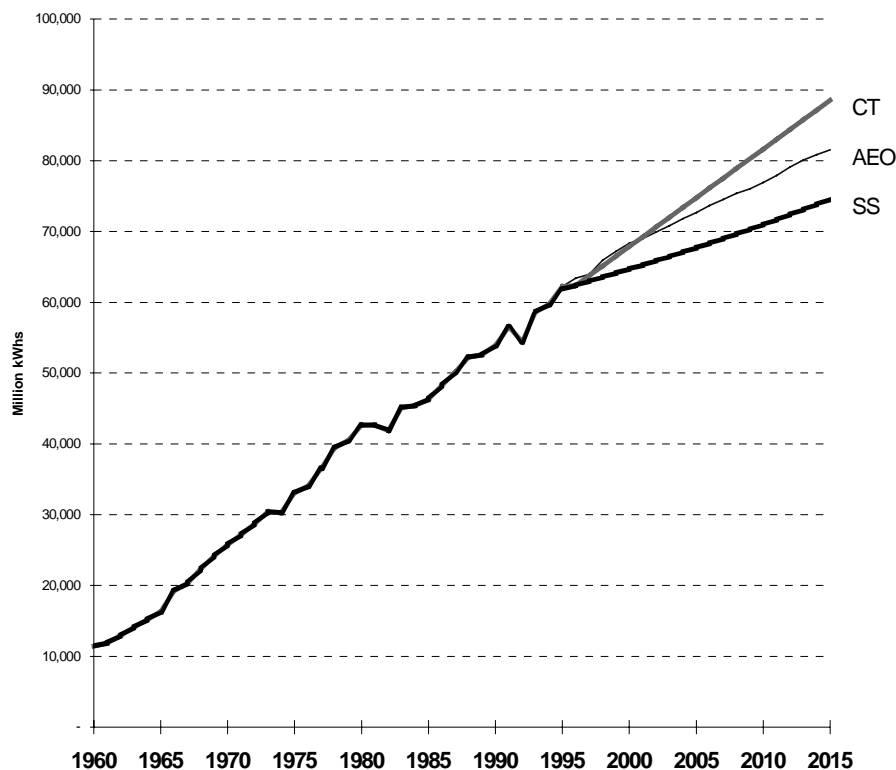
The CT projection pictured in Table 6 reflects the trend of electricity sales since the 1980s. Based on least-squares linear regression, it assumes that past trends in state electricity sales will continue into the future. The study's reference case for the CT sales projection is based on analysis of 1980 to 1994 trends in the residential sector and 1984 to 1994 trends in the commercial and industrial sectors.[28] Chart 9 presents the CT projections for in-state sales increases through 2015, and the projected percentage increases with respect to the base year 1990. Between 1995 and 2015, residential sales are projected to grow at an annual rate of about 1.6 percent, commercial sales at a much higher 2.4 percent rate and industrial sales at only about 1 percent per year.

Table 6 - Continuing Trent (CT) standard case estimate of future electricity sales in Missouri, based on sales trends since 1980-84

Units: Million kWh

	Resid.	Comm.	Indust.	Total
1984	18,490	14,576	12,342	**45,408**
1990	21,652	19,335	12,937	**53,925**
1995	25,409	22,493	14,321	**62,222**
2000	27,224	25,825	14,842	**67,891**
2005	29,866	29,230	15,674	**74,770**
2010	32,507	32,636	16,507	**81,650**
2015	35,149	36,042	17,339	**88,529**
Percent increase	*62%*	*86%*	*34%*	**64%**
Growth rate 1984-1995	2.93%	4.02%	1.36%	**0.90%**
Growth rate 1995-2015	1.64%	2.39%	0.96%	**1.78%**

Although the CT projection is proposed as the "high" sales estimate in this study, it may be conservative. In their 1994 and 1995 Integrated Resource Plans (IRPs), AmerenUE forecasted annual sales growth of 1.8 percent through 2005, and Kansas City Power and Light forecasted annual sales growth of 2.3 percent through 2015.[29] The two utilities account for about 57 percent of in-state sales to electricity end users.[30]

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[28] Commercial and industrial sales growth are regressed on the 1984 to 1994 trend because of discontinuities in the USDOE/EIA State Energy Data System (SEDS) database for these sectors between 1980 and 1984. USDOE/EIA, *State Energy Data Report 1994*, p. 398.

[29] AmerenUE, *Energy Resource Plan*, June 1995, p. 15; Kansas City Power and Light (KCPL), *KCPlan 94: Integrated Resource Plan (1995-2014)*, Volume 1: Summary, p. III-4.

[30] This estimate is based on analysis of utility-level USDOE/EIA data compiled from reports submitted by Missouri utilities using Form EIA861.

Chart 9 illustrates the CT projections that result from trend analysis based on electricity sales since 1960, 1970 and 1980. Nationally, electricity demand grew at nearly twice the rate of economic growth during the 1960s, slowed in the 1970s to about 1.5 times the rate of economic growth and slowed further in the 1980s to about the same rate as economic growth. Accordingly, the sales trend line based on 1980 to 1994 electricity sales in Missouri is flatter than the other trend lines in Chart 9. A return to sales trends that prevailed in earlier decades would imply higher electricity sales; however, some of this growth was due to the introduction of services and appliances that have since saturated the market.

Chart 9 - Comparison of CT standard and alternative case projections of future Missouri electricity sales
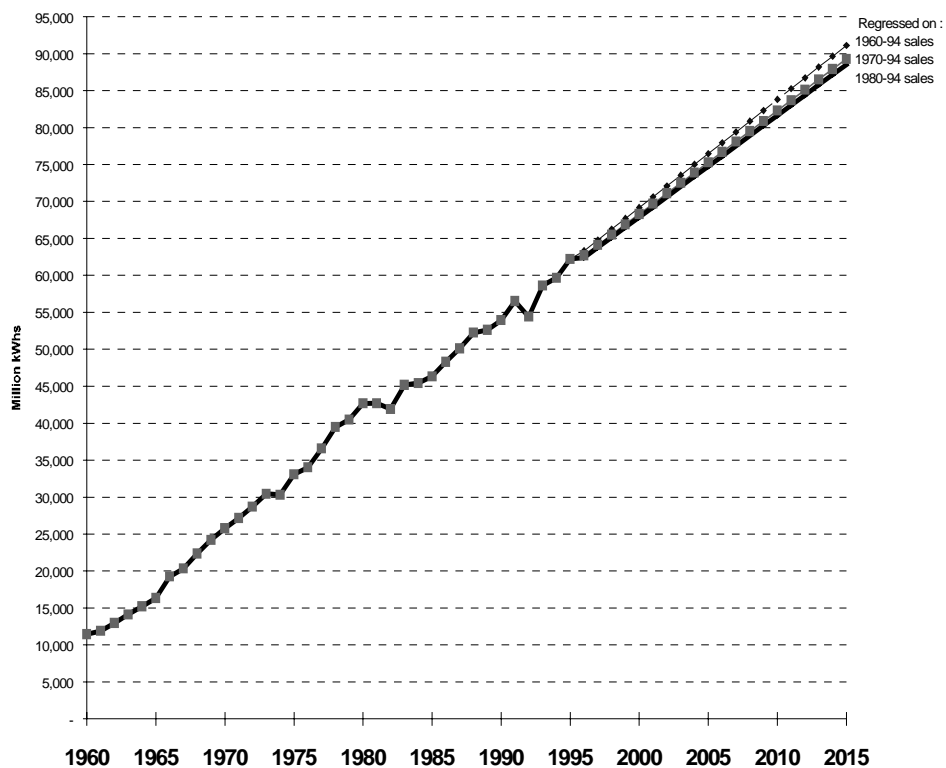
The AEO projections for Missouri electricity sales are extrapolated from AEO regional projections for the residential and commercial sectors and from AEO national projections for the industrial sector. The *Annual Energy Outlook 1997* bases its standard-case projections of national and regional electricity sales on the assumption that future electricity sales will not grow as rapidly in the future as from 1980 to 1994. Therefore, the AEO projection for future electricity sales is lower than the CT projection.

Future electricity sales per person in Missouri's residential and commercial sectors were projected under the assumption that they will grow at the same rate as *Annual Energy Outlook 1997* per capita projections for the North West Central census region, which includes Missouri. Industrial-sector sales were projected under the assumption that they will grow at the same rate as AEO projections for the this region.[31]

Table 7 summarizes the projections for sales in the residential, commercial and industrial sectors and the projected percentage increase with respect to the base year, 1990. The projected 51 percent increase in aggregate sales over the 1990 base year compares to the CT estimate's projection of a 64 percent increase during the same period. Residential sales are projected to grow by 1.1 percent, commercial sales by 1.4 percent, and industrial sales by 1.8 percent between 1995 and 2015.

Table 7 - AEO estimate of future electricity sales in Missouri

Units: Million kWh

	Resid.	Comm.	Indust.	Total
1984	18,490	14,576	12,342	*45,408*
1990	21,652	19,335	12,937	*53,925*
1995	25,409	22,493	14,321	*62,222*
2000	27,605	24,574	16,143	*68,323*
2005	28,475	26,549	17,632	*72,656*
2010	29,805	28,107	19,024	*76,936*
2015	31,650	29,458	20,441	*81,548*
Percent increase	46%	52%	58%	*51%*
Growth rate 1984-1995	2.93%	4.02%	1.36%	*0.90%*
Growth rate 1995-2015	1.10%	1.36%	1.80%	*1.36%*

Per capita electricity use in Missouri's residential and commercial sectors are high relative to the regional average. In 1994, per capita sales of electricity in Missouri's residential sector equaled 4.56 million kWh per person, and, in the commercial sector, 4.08 million kWh per person. Of other states in the North West Central census region, only North Dakota had higher per-capita residential electricity consumption, and only Nebraska had higher per-capita commercial consumption.

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[31] North West Central projections of industrial electricity sales growth were used in preference to national projections because the *Annual Energy Outlook 1997* projects that national industrial electricity sales will grow more slowly (1.46 percent) than regional sales (1.80 percent). However, the regional projection could not be adjusted for the differential rate of economic growth because there are no readily available projections of gross regional project (GRP) for census districts. Therefore, the analysis assumes a GSP growth rate of 1.9 percent for Missouri and a GRP growth rate of 1.9 percent for the North West Central region. When the analysis is conducted using the AEO projection for national industrial electricity sales, Missouri sales projections for 2015 are as follows: 20,535 billion kWh assuming high GSP growth; 18,934 billion kWh assuming moderate GSP growth; and 17,244 billion kWh assuming slow GSP growth. The resulting AEO estimate of aggregate in-state electricity sales under moderate growth is 80,041 billion kWh. As stated in the text, the analysis uses a 2.315 percent annual growth rate for high GSP growth, a 1.9 percent rate for moderate growth and a 1.4 percent rate for slow GSP growth.

Chart 10 depicts the changes in residential per-capita electricity use implied by the CT and AEO projections for Missouri consumption as well as the AEO projection for the North West Central region as a whole. The AEO analysis projects a distinct flattening of the growth curve, roughly parallel to the regional growth curve. The CT analysis projects continued growth consistent with trends from 1980 to 1994.

As Chart 11 indicates, the AEO analysis projects more substantial growth in commercial per-capita electricity use. However, the growth is slower than the CT projection and flattens over time.

The *Annual Energy Outlook 1997* anticipates that a number of factors will reduce the historic growth rate of residential and commercial electricity demand, including projected lower housing starts and commercial floor-space additions, market saturation of current electric appliances, equipment efficiency improvements including commercial lighting due to technical innovation and legislated standards, and utility investments in demand-side management.

However, the AEO study also cites possible developments that could offset these factors, such as the introduction of new appliances, rapid economic growth and lower electricity prices resulting from market restructuring.[32]

Chart 10 - CT and AEO projections of residential per-capita demand for electricity

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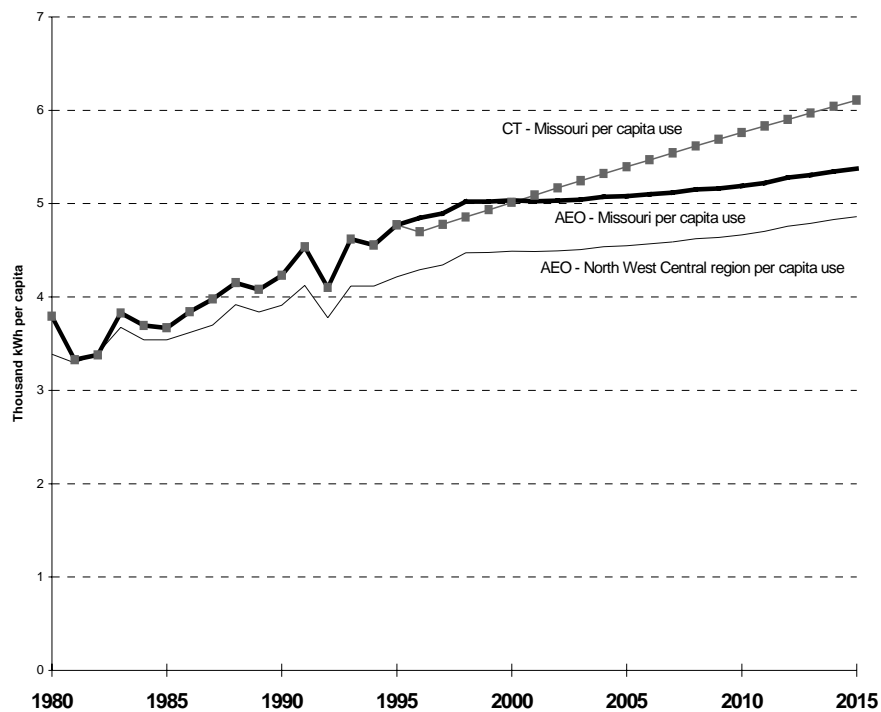
[32] *Annual Energy Outlook 1997*, pp. 41, 48, 52-53, 76. Nationally, utility investments in new demand-side management efforts appear to have slowed as attention has shifted to market restructuring.

Chart 11 - CT and AEO projections of commercial per-capita demand for electricity
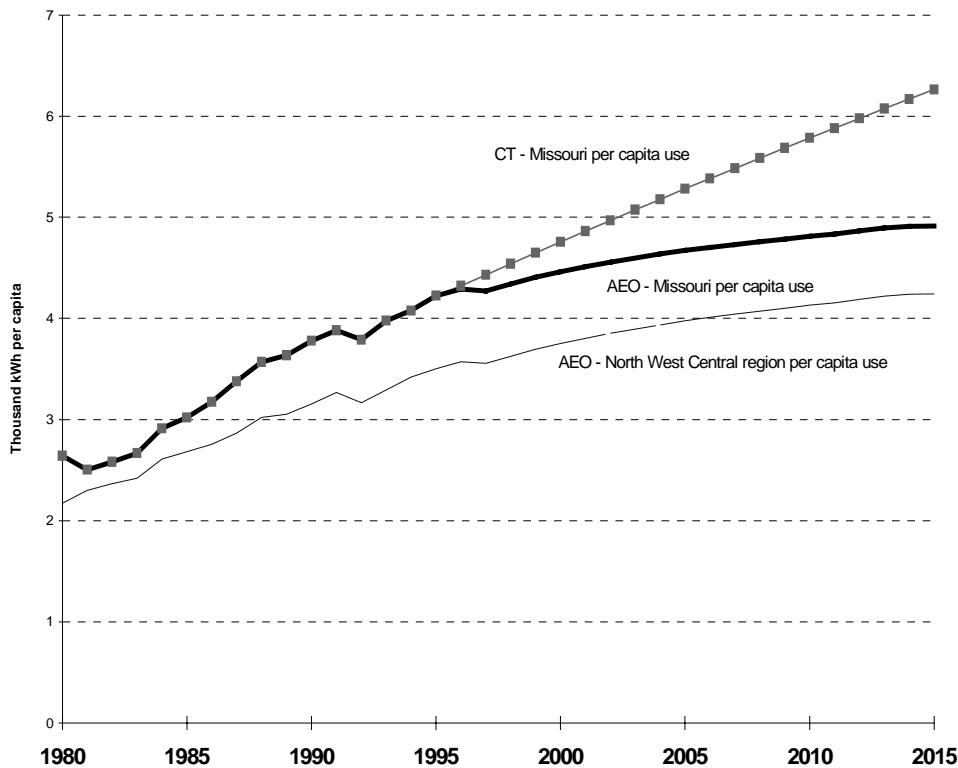
The *Annual Energy Outlook 1997* projects continuing decreases in industrial energy intensity, including use of electricity, because of a combination of efficiency gains and a structural shift toward less energy-intensive industries.[33] The top line in Chart 12 illustrates the projected decline in electricity intensity for industry nationally. The CT projection for Missouri industrial electricity sales, based on past trends, indicates a continued decline in energy intensity roughly parallel to that which the *Annual Energy Outlook 1997* projects for the U.S. However, the AEO extrapolation from North West Central regional projections indicates a flattening of industrial electricity sales per unit of gross state product (GSP) and a growing convergence between Missouri's industrial electricity intensity and that of industry nationally.

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[33] *Annual Energy Outlook 1997*, pp. 42, 47.

Missouri's industrial sector is already weighted toward less energy-intensive industry than in the U.S. industry as a whole. Since structural change is one of the components of the USDOE/EIA's forecast, it is reasonable that the drop in energy intensity in Missouri may not be as steep as nationally. It is also possible that, at a state level, the movement of a particular energy-intensive industry into or out of Missouri could strongly influence industry's average energy intensity.

Chart 12 - CT and AEO projections of industrial demand for electricity per unit of Gross State Product
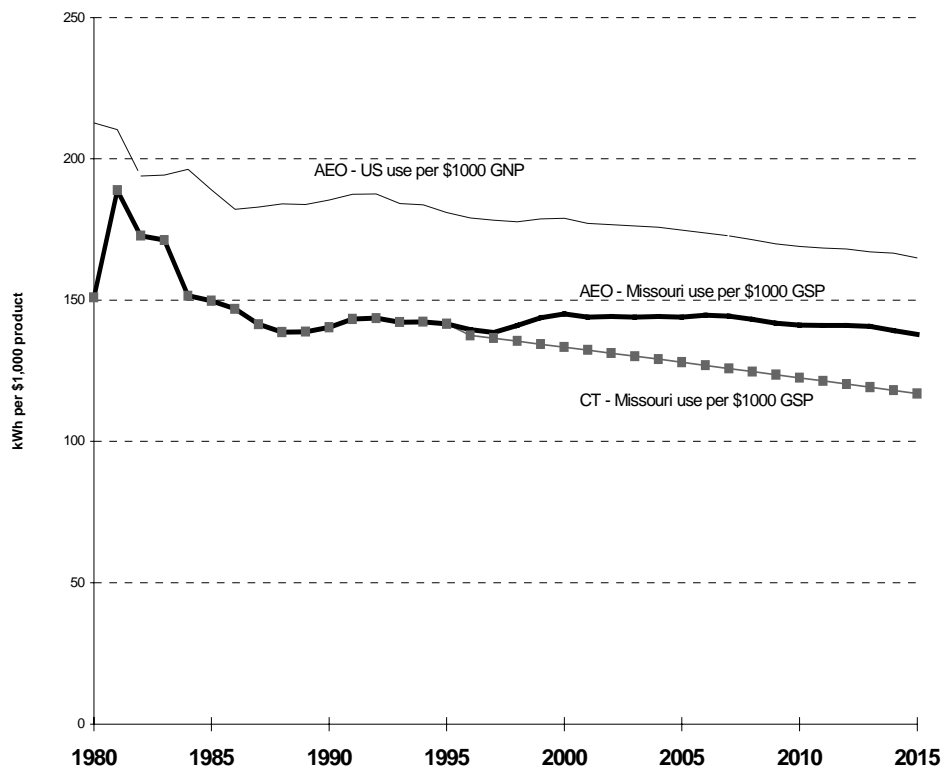
National Electricity sales forecasts from consulting firm Data Resources, Inc./McGraw-Hill are about equal to the *Annual Energy Outlook* forecast, but two other national consulting firms, The WEFA Group (formerly the Wharton Econometric Forecasting Associates) and Gas Research Institute, give somewhat higher forecasts than the *Outlook*.[34] Review of these forecasts suggests it is prudent to construct high and low sales scenarios rather than attempt a single forecast.

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[34] *Annual Energy Outlook 1997,* Table 19, p. 79.

Section 2: Estimates of future export sales

In recent years, there has been a near balance between in-state electricity generation and sales in Missouri; about as much electricity is generated in Missouri and sold for consumption within the state. Missouri was a net importer of electricity for several years before 1970 and, with the exception of 1993, has been a net exporter since 1970.[35] Chart 13 depicts the relationship of in-state generation and sales from 1990 to 1995.[36]

Chart 13 - Missouri utility electricity sales and generation, 1990-95

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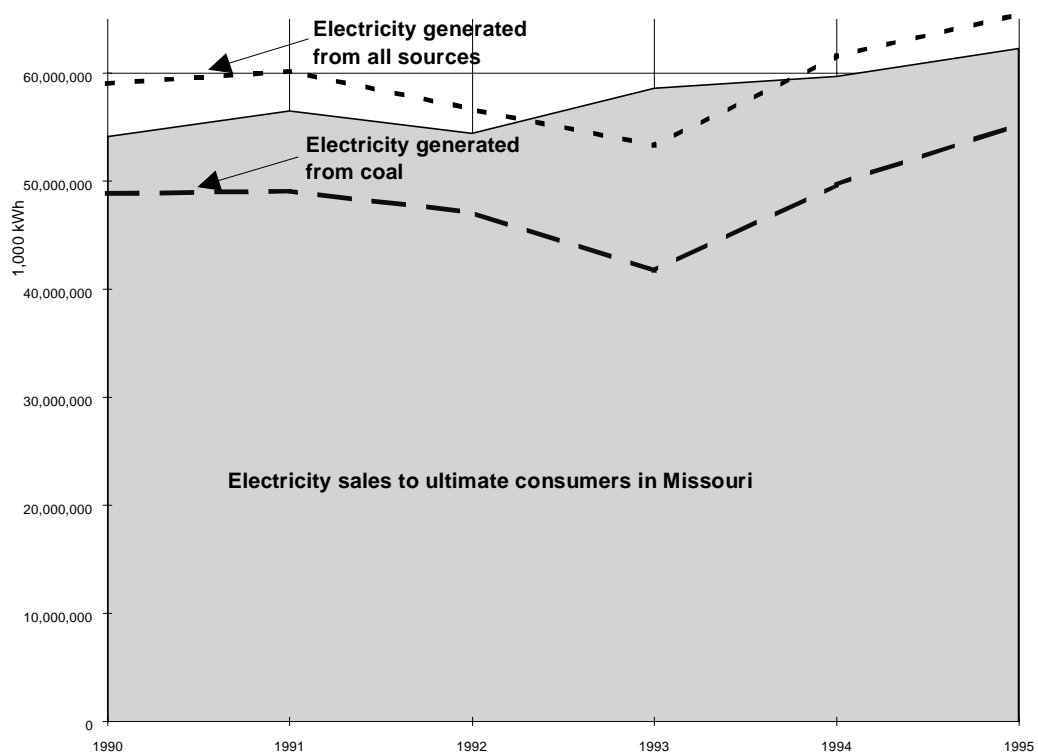
[35] Based on analysis of variables in the USDOE/EIA, SEDS system, Missouri was a net importer for several years before 1970, exported up to 20 percent of in-state sales between 1970 and 1985, and has exported about 5 percent of in-state sales in recent years. Interpretation of the variables is complicated by the fact that several large investor-owned utilities have customers and generating facilities in adjacent states.

[36] The chart provides sales only through 1995 because electricity sales data is not yet available for 1996. In the year 1993, because of impacts of flooding on generating plants, in-state sales exceeded in-state generation, but this is one of only three anomalous years over the past four decades.

The export rate between 1990 and 1996 can be estimated by comparing the total power (million kWh) generated by utilities in Missouri to total sales of electricity (million kWh) to Missouri ultimate consumers, as follows:

	1990	1991	1992	1993	1994	1995	1996
Total generated	50,046	60,171	56,661	53,277	61,586	65,442	67,853
Missouri sales	53,925	56,514	54,411	58,622	59,683	62,222	63,384
Export rate	9.5%	6.5%	4.1%	-9.1%	3.2%	5.2%	7.1%

Based on these estimates, a conservative estimate is that Missouri utilities export about 5 percent of the power that they generate in the state each year. The year 1993 must be considered an anomaly. Net electricity imports occurred in 1993 because flooding and a strike by Eastern coal miners reduced the supply of coal to Missouri utilities. Given the extraordinary nature of the 1993 flood and the shift of Missouri utilities from eastern to western suppliers of coal after 1993, these circumstances seem unlikely to recur.

The balance of in-state sales and generation could change under market restructuring and environmental regulations. Under a restructured market system, electricity exports may become more important to Missouri utilities, and electricity imports may become more important to Missouri consumers. Given the relatively low average price of electricity generated in Missouri, restructuring seems more likely to lead to the increased use of coal-fired and other generating capacity in Missouri than to its decreased use or abandonment.[37] On the other hand, NO_x regulations under USEPA's NO_x SIP call may increase the attractiveness of importing power from states not covered by the rule. This could affect utility investment and contract decisions that influence Missouri's electricity export rate.

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[37] Average revenue per kilowatt-hour of electricity generated in Missouri in 1994 was 6.28 cents, compared to the U.S. average of 6.91 cents per kilowatt-hour. Prices paid by specific customers or groups of customers vary from average revenue per kilowatt-hour. USDOE/EIA, *Electric Sales and Revenue* 1994.

Section 3: Extent of coal-fired generating capacity in Missouri

Current coal-fired generating capacity in Missouri places an upper limit on short- and intermediate-term CO_2 emissions from coal, due to the relatively long lead time required to construct new facilities. Existing Missouri coal-fired utility plants have substantial unused generating capacity. In 1995, Missouri utilities owned coal-fired steam electric generators capable of generating up to about 78.7 million megawatt-hours of electricity per year, allowing for scheduled maintenance and forced outages.[38] Some unused capacity was soaked up between 1990 and 1996 as electric generation from Missouri coal-fired utility plants increased by about 18 percent, from about 48.5 million to about 57.2 million megawatt-hours. Nevertheless, assuming that a coal plant may generate up to 85 percent of its rated summer capability, actual power generation from Missouri's coal-fired utility plants in 1996 was about 73 percent of potential generation.

In theory, Missouri coal-fired plants could generate an additional 21.5 million megawatt-hours of electricity per year. On the same basis, Missouri coal-fired plants could consume up to 817 trillion Btus of coal,[39] compared to 606 trillion Btus consumed in 1996, and could emit up to 85 million tons of CO_2 compared to 63 million tons in 1996.

The practical limit to Missouri's current coal-fired capacity may be lower than that described above. Several factors could limit current capacity:

- The transmission capability serving some coal-fired plants may limit their practical capacity to less than the theoretical limit.

- Some unused capacity may consist of units where the optimal level of production is less than theoretical capacity and production at theoretical capacity is not economically viable.

- Some unused capacity may consist of inefficient units, which would require upgraded equipment and technology in order to be competitive. Although coal-fired steam plants normally have a long life, up to 65 years, some may be retired before 2015. For example, the National Energy Modeling System (NEMS), on which *Annual Energy Outlook 1997* is based, assumes that plants with total operational costs exceeding 4 cents per kilowatt-hour are marked for retirement.

- A restructured market could increase the incentive to retire inefficient plants or repower them. Depending on the course that restructuring takes, it could either enhance the environment for independent power producers or create barriers. In general, the prospect of restructuring increases the uncertainty of predicting utility and non-utility investment decisions.

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[38] Estimated by multiplying the net summer capability of coal-fired generators (10,575 MW), 6 x 8,760 hours per year, and then by a 0.85 average capacity factor to discount for scheduled maintenance and forced outages.

[39] Estimated by multiplying the theoretical generating capability of Missouri utilities (see Footnote 38), by the calculated average of Missouri coal consumption per mWh (10,500 Btus/mWh). This heat rate is an average for Missouri calculated from Missouri utility data reported on form EIA759 for 1990 to 1996. The utilities reported the quantity of coal burned and power generated from coal. If new coal plants are built, they may have a better heat rate (as low as 9,300 Btus/mWh), but Missouri utilities have not made public any firm plans to build new coal capacity in the state, and such investments are unlikely during the early years of deregulation.

The CO_2 emissions potential of coal-fired plants could be reduced by utility efforts to improve plant generating efficiency, indicated by heat rates. If the generating efficiency of facilities improves, less coal needs to be burned to achieve a given level of generation. Therefore, an improvement in the average heat rate for coal-fired facilities could reduce Missouri utilities' potential coal consumption and CO_2 emissions.

Efforts to improve heat rates are part of normal utility management and will occur. However, based on the reported results of voluntary efforts by some utilities to reduce CO_2 emissions by reducing heat rates, utility efforts to improve heat rates are unlikely to reduce coal consumption and emissions by more than about 1 percent.[40]

The CO_2 emissions potential of coal-fired plants could be increased by future construction. With the prospect of market restructuring increasing the uncertainty facing utilities, they have become reluctant to invest in highly capital-intensive projects such as coal-fired plants. Missouri utilities have no current plans to expand to coal-fired capacity before 2015 and generally have preferred purchasing power under wholesale contract to long-term capital commitments. However, new coal-fired projects are a future possibility if market restructuring results in increasing electricity sales and if, as seems likely, there are reduced opportunities to contract for other utilities' surplus power.

One of the chapter's scenarios for utility CO_2 emissions during 1995 through 2015 includes construction of additional coal-fired generating capacity toward the end of the period. The scenario assumes that Missouri utilities will take advantage of advanced coal technologies that deliver lower heat rates than current Missouri coal-fired plants.[41] The resulting efficiency would result in lower CO_2 emissions than would occur with a less-efficient, coal-fired plant. Nevertheless, because coal has a higher carbon content than natural gas, CO_2 emissions from even a very efficient coal-fired plant will be higher than those from a natural gas turbine.

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[40] USEPA, Voluntary Reporting of Greenhouse Gas Emissions, 1996.

[41] USDOE/EIA assumes declining heat rates for new coal technologies averaging 9,463 Btus/kWh for pulverized coal and 7,582 Btus/kWh for advanced coal in 2010. This contrasts with the average heat rate of 10,373 in Missouri coal-fired plants between 1990 and 1996. *Assumptions for the Annual Energy Outlook 1997*, Table 33, p. 58.

Section 4: Specification of the model

Three sets of equations specify the model developed in this chapter:

1) Equations to estimate total CO_2 emissions (E_t) as an aggregate of emissions from coal (E_c), petroleum (E_p), and natural gas (E_n). For each fuel, emissions are estimated by multiplying the quantity consumed by an emissions coefficient (Equations 2-4). To obtain the quantity of natural gas and petroleum, the model uses the values estimated in Part 1, with the CT estimates feeding the high-sales scenarios and the AEO estimates feeding the low-sales scenarios. The quantity of coal burned is an output of the model (Equation 5), based on an estimate of how much power needs to be generated from this source to meet demand.

$$
\begin{aligned}
1. \quad & E_t = E_c + E_n + E_p \\
2. \quad & E_c = Q_c * C_c \\
3. \quad & E_n = Q_n * C_n \\
4. \quad & E_p = Q_p * C_p \\
5. \quad & Q_c = Gc * 1/Hc
\end{aligned}
$$

2) Equations to estimate electricity generated from coal, based on the assumed accounting relationship between net sales (Snet) and generation from coal (G_c) and other sources such as natural gas (G_n) and petroleum (G_p) (Equation 6). Generation from petroleum is estimated based on heat rate (Equation 7). The model uses one of the net sales estimates from Part 2, Section 1, with the CT estimate feeding the high-sales scenarios and the AEO estimate feeding the low-sales scenarios. Net sales is aggregated from sales to the residential, commercial and industrial sectors (Equation 7).

$$
\begin{aligned}
6. \quad & Gc = Snet - (Gn+Gp+Gk+Gh) \\
7. \quad & Gp = Qp * 1/Hp \\
8. \quad & Snet = Sr+Sc+Si+Sx
\end{aligned}
$$

3) An equation to estimate natural gas consumption and power generated from natural gas follows. The equation assumes that total natural gas consumption will be distributed across existing and new technology, following a distribution chart such as the hypothetical chart shown below.

$$
\begin{aligned}
& Gn = Gne + Gno1 + \ldots + Gn \\
& Gne = Qne * 1/Hne \\
& Gnb = Qnb * 1/Hnb \\
& Gno = Qno * 1/Hno \\
& Qnb = Rnb* Qnn \\
& Qno = (1-Rnb)* Qnn \\
& Gp = Qp * 1/Hp
\end{aligned}
$$

Table 8 presents the hypothetical distribution of natural gas consumption across technologies, which was used for the "HighNG" scenarios and which assume high consumption of natural gas. For the HighNG scenarios, consumption of natural gas reaches 96 trillion Btus in 2015.

Current capacity and planned additions should bring Missouri utilities' total natural gas capacity to about 3,200 megawatts by about 2003. The distribution in Table 8 could be met if utilities add another 500 to 1,000 MW of efficient dual steam capacity and 1,250 MW of combined-cycle capacity coming on line during 2003 through 2015.[42]

Table 8 - Hypothetical distribution of natural gas consumption across technologies for the "high" natural gas scenarios

	Dual Steam	Combined Cycle (1995)	Combined Cycle (1995)	Combined Cycle (2010)	Combined Cycle (2010)
2003	100.0%	0.0%	0.0%		
2004	100.0%	0.0%	0.0%		
2005	40.0%	30.0%	30.0%		
2006	35.0%	32.5%	32.5%		
2007	35.0%	32.5%	32.5%		
2008	30.0%	35.0%	35.0%		
2009	30.0%	35.0%	35.0%		
2010	25.0%	33.9%	33.9%	3.6%	3.6%
2011	20.0%	32.8%	32.8%	7.2%	7.2%
2012	20.0%	29.2%	29.2%	10.8%	10.8%
2013	17.0%	27.1%	27.1%	14.4%	14.4%
2014	14.0%	24.9%	24.9%	18.1%	18.1%
2015	14.0%	23.7%	23.7%	19.3%	19.3%

Table 9 lists and explains the exogenous variables used by the model and those which are determined within the model.

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[42] Total capacity was estimated by (1) estimating megawatt-hours generated from each technology type using the heat rates indicated in the distribution table and (2) converting to megawatt capacity assuming 8,760 hours in the year and capacity factors of 6 percent for the pre-2003 steam units, 12-25 percent for the post-2003 steam units and 85 percent for the combined-cycle units.

Table 9 - Variables in the Missouri power generation accounting model

Variable	Description (all quantities assumed to be at state level)	Units	Source and default value
Et	Total CO_2 emissions.	tons	Estimated from model
Ec, En, Ep	CO_2 emissions from coal, natural gas and petroleum.	tons	Estimated from model
Qc	Quantity of coal burned.	Btus	Estimated from model
Qn	Quantity of natural gas burned.	Btus	Given by scenario
Qp	Quantity of petroleum burned.	Btus	Given by scenario
Cc	CO_2 coefficient to determine coal CO_2 emissions from quantity (Btus) of coal:	tons CO_2/Btus	208.7 - USDOE/EIA State Energy Report 1994, Appendix F
Cn	CO_2 coefficient to determine natural gas CO_2 emissions from quantity (Btus) of natural gas:	tons CO_2/Btus	116.4 - Derived from 1990 Inventory
Cp	CO_2 coefficient to determine petroleum CO_2 emissions from quantity (Btus) of petroleum:	tons CO_2/Btus	161.0 - Derived from 1990 Inventory
H_c	Average heat rate for generation from coal. The model could be expanded to include advanced coal technologies by specifying alternative heat rates and the distribution across coal technologies.	Btus/kWh	10.3729 Estimated from 1990 to 1996 EIA759 data for Missouri utilities
H_{n1}	Average heat rates for generation from existing (peaking) natural gas facilities. The inverse converts from generation (kWh) to quantity (Btus) of natural gas.	Btus/kWh	12.8875 Estimated from 1990 to 1996 EIA759 data for Missouri utilities
$H_{n2}...H_{nn}$	Average heat rate for generation from combined cycle natural gas turbines. The inverse converts from generation (kWh) to quantity (Btus) of natural gas. The model could be expanded to include additional advanced natural gas technologies by specifying alternative heat rates and the distribution across gas technologies.	Btus/kWh	6.8000 - USEPA CAPI program
	New dual steam		9.5000
	Combined Cycle 1995		8.0300
	Combined Cycle 2010		7.0000
	Advanced Combined Cycle 1995		6.9850
	Advanced Combined Cycle 2010		5.7000

Variable	Description (all quantities assumed to be at state level)	Units	Source and default value
Hp	Average heat rate for generation from petroleum. The inverse converts from generation (kWh) to quantity (Btus) of petroleum.	Btus/kWh	13.9750 - estimated from 1990-96 EIA759 data for Missouri utilities
Snet	Net sales of electricity.	kWh	Aggregated from individual sources
Sr	Sales to Missouri's residential sector.	kWh	Estimated from historic sales or AEO regional projections using CT or AEO methods
Sc	Sales to Missouri's commercial sector.	kWh	Estimated from historic sales or AEO regional projections using CT or AEO methods
Si	Sales to Missouri's industrial sector.	kWh	Estimated from historic sales or AEO regional projections using CT or AEO methods
St	Sales to Missouri's transportation sector.	kWh	Assumed zero, but may be estimated from historic sales or AEO projections
Sx	Electricity exports.	kWh	Estimated as a percentage of sales to Missouri sectors
Gc,	Electricity generated from coal combustion.	kWh	Estimated from model
G_p	Electricity generated from natural gas, petroleum, nuclear and hydroelectric sources.	kWh	Estimated from scenario-derived quantity of petroleum
Gk, Gh	Electricity generated from nuclear and hydroelectric sources.	kWh	Assumed constant at 1990-96 average
G_{nt}	Total (t) electricity generated from natural gas combustion.	kWh	Aggregated from Gne Gno and Gnb
G_{n1}	Electricity generated from natural gas combustion in "existing" (pre-2003) facilities.	kWh	Estimated based on the proportioning of natural gas use into the three facility types
$G_{n2...}G_{nn}$	Electricity generated from natural gas combustion in new facilities based on technologies "2" through "n."		
Q_{n1}	Quantity of natural gas burned by utilities in existing (pre-2003) facilities.	Btus	Historic data and scenario projections through 2002
Qn2...Qnn	Quantity of natural gas burned by utilities in other facilities.	Btus	Given by scenario

Worksheet 1 shows the model calculations for the two AEO (low sales) scenarios — the high natural gas (HighNG) and low natural gas (LowNG) scenarios. Because of space limitations, several columns that appear in the actual worksheet have been removed from the printed page. The missing columns are those used to account for generation from nuclear, hydroelectric and petroleum sources, and the final columns showing total CO_2 emissions. The worksheet for the high sales scenarios is similar in form and is not shown.

The three leftmost columns in the worksheets are for input estimates of annual electricity sales. Exports are estimated as a percentage of in-state sales. The next set of six unshaded columns is used for the input of low and high estimates of natural gas (NG) energy and the calculation of generation from natural gas and the associated CO_2 emissions. The final set of six shaded columns is used to estimate generation from coal, use of coal and CO_2 emissions. Projected CO_2 emissions are estimated by summing the projected CO_2 emissions from petroleum, natural gas and coal generation.

Worksheet 1 – Model spreadsheet for low sales (AEO) scenario calculations

	In-State Sales (million kWh)	Export Sales (million kWh)	Net Sales (million kWh)	NG Energy Low (trillion Btus)	High	NG Generation Low (million kWh)	High	Natural Gas CO_2 Low (1,000 T)	High	Coal Generation LowNG (million kWh)	HighNG	Coal Energy Use LowNG (million kWh)	HighNG	Coal CO_2 Emissions LowNG (1,000 T)	High NG
1990	53,925	10%	59,317	4	4	278	278	207	207	48,854	48,854	502.87	502.87	51,238	51,238
1991	56,514	5%	59,340	13	13	1,000	1,000	746	746	49,070	49,070	499.60	499.60	50,997	50,997
1992	54,411	5%	57,131	2	2	184	184	137	137	47,094	47,094	490.68	490.68	50,124	50,124
1993	58,622	-10%	52,760	5	5	383	383	285	285	41,710	41,710	438.71	438.71	45,284	45,284
1994	59,683	5%	62,668	4	4	338	338	252	252	49,662	49,662	516.23	516.23	53,458	53,458
1995	62,222	5%	65,333	13	13	996	996	743	743	55,280	55,280	568.82	568.82	59,362	59,362
1996	63,384	5%	66,553	5	5	381	381	284	284	57,657	57,657	606.16	606.16	63,453	63,453
1997	63,959	5%	67,157	5	4	366	329	275	247	56,484	56,521	585.90	586.29	61,139	61,179
1998	65,940	5%	69,237	6	9	479	727	359	546	58,453	58,205	606.33	603.75	63,270	63,001
1999	67,191	5%	70,550	9	19	685	1,458	514	1,093	59,563	58,790	617.84	609.82	64,471	63,635
2000	68,323	5%	71,739	9	19	697	1,501	523	1,126	60,742	59,938	630.06	621.73	65,747	64,877
2001	69,019	5%	72,470	9	20	705	1,529	529	1,147	61,467	60,643	637.59	629.04	66,532	65,640
2002	69,928	5%	73,424	10	22	756	1,709	567	1,282	62,372	61,418	646.98	637.08	67,512	66.480
2003	70,807	5%	74,348	10	22	763	1,744	572	1,301	63,290	62,309	656.50	646.32	68,506	67,443
2004	71,831	5%	75,423	11	26	850	2,164	638	1,533	64,280	62,967	666.77	653.14	69,577	68,155
2005	72,656	5%	76,289	13	34	1,023	3,208	768	1,995	64,975	62,790	673.98	651.32	70,329	67,965
2006	73,656	5%	77,338	14	37	1,078	3,533	808	2,139	65,972	63,516	684.32	658.85	71,409	68,751
2007	74,536	5%	78,262	15	40	1,145	3,918	859	2,320	66,830	64,058	693.22	664.46	72,337	69,337
2008	75,375	5%	79,144	16	43	1,216	4,347	912	2,508	67,643	64,512	701.65	669.18	73,217	69,829
2009	76,034	5%	79,836	16	45	1,257	4,580	943	2,616	68,296	64,973	708.43	673.95	73,924	70,327
2010	76,936	5%	80,782	18	50	1,376	5,352	1,032	2,931	69,126	65,150	717.04	675.79	74,823	70,519
2011	77,915	5%	81,811	20	60	1,586	6,709	1,189	3,490	69,947	64,824	725.55	672.41	75,711	70,166
2012	79,102	5%	83,057	21	62	1,631	7,057	1,224	3,611	71,149	65,724	738.02	681.74	77,013	71,140
2013	80,070	5%	84,074	23	70	1,796	8,191	1,347	4,050	72,003	65,609	746.88	680.55	77,937	71,015
2014	80,875	5%	84,919	29	92	2,280	11,395	1,710	5,338	72,366	63,251	750.64	656.09	78,329	68,463
2015	81,548	5%	85,626	31	96	2,375	12,039	1,781	5,589	72,980	63,316	757.02	656.77	78,995	68,534

Section 5: Results of scenario analysis

Two factors distinguish the four "extended" scenarios developed using the procedures in Sections 4: the amount of additional power that Missouri utilities must generate, and the choice between coal and natural gas as the way to supply this additional power.

The choice between coal and natural gas is discussed in Part 1, Section 2 of this chapter. As was indicated in Table 1 at the beginning of this chapter, the four scenarios can be divided into LowNG and HighNG scenarios. The four scenarios can be divided into low-sales and high-sales. For the high-sales scenarios, in-state electricity sales projections were estimated based on simple linear regression from past sales. For low-sales scenarios, in-state electricity sales projections were estimated based on extrapolation from *Annual Energy Outlook 1997* projections. These procedures were described in Part 2, Section 1.

Low sales scenarios: Table 10 summarizes the aggregate CO_2 emissions projected by the two extended scenarios whose in-state electricity sales projections were calculated based on extrapolation from *Annual Energy Outlook 1997* projections. Assuming low natural gas use (LowNG), emissions grow to a maximum of about 81 million tons in 2015, a midrange estimate of emissions. Assuming high natural gas use (HighNG), emissions grow to a maximum of about 75 million tons in 2013 before dropping slightly in 2014 and 2015, a low-emissions estimate.

Table 10 - Estimated CO$_2$ emissions under AEO (low sales) scenarios

Units: 1,000 Short Tons Carbon Dioxide (CO$_2$)

Estimated CO$_2$ emissions	AEO-LowNG	AEO-HighNG
1990	51,540	51,539
1996	63,855	63,854
2000	66,283	66,016
2005	71,110	69,972
2010	75,884	73,479
2015	80,877	74,224

Increase over 1990 baseline	AEO-LowNG	AEO-HighNG
1996	12,316	12,315
2000	14,743	14,477
2005	19,570	18,434
2010	24,344	21,941
2015	29,338	22,686

% increase over 1990 baseline	AEO-LowNG	AEO-HighNG
1996	23.9%	23.9%
2000	28.6%	28.1%
2005	38.0%	35.8%
2010	47.2%	42.6%
2015	56.9%	44.0%

The HighNG scenario projects a 1.5 percent annual growth rate for CO$_2$ emissions, with only a 4 million ton increase after 2005. Under the HighNG scenario, coal generation and CO$_2$ emissions stabilize after 2005, and total CO$_2$ emissions stabilize after 2010.

In contrast, the LowNG scenario projects a 1.8 percent annual growth rate in CO$_2$ emissions between 1990 and 2015, with more than half the increase in emissions occurring after 2005.

Since the two scenarios use the same estimate of in-state electricity sales, they differ primarily in that utilities under the LowNG scenario continue to generate electricity using the same resource mix that prevailed in 1996, whereas the HighNG scenario is a fuel-switching scenario. Under the HighNG scenario, utilities bring about 1,250 megawatts of base-load natural gas generating capacity into production during the years after 2004, and actually reduce coal consumption during four separate production years, 2004/2005, 2010/2011, 2012/2013 and 2013/2014.

In 2015, under the HighNG scenario, utilities generate more than 12 billion kWh, including some intermediate or base-load power, from natural gas-fired facilities. Under the LowNG scenario, they generate only about 2.4 billion kilowatt-hours of electricity from natural gas in 2015, primarily power used to meet peak demand.

The HighNG introduction of additional power from natural gas reduces total coal generation by 9.7 billion kWh and total CO_2 emissions from coal by 10.5 million tons. Although CO_2 emissions from natural gas increase by 3.8 million tons, net CO_2 emissions are about 6.7 million tons lower under HighNG compared to LowNG.

The results of the HighNG scenario depend on the assumptions about natural gas consumption, heat rates and distribution across technologies specified above. More significantly, the HighNG scenario assumes that utilities would have a reason to stabilize or reduce consumption of coal after 2005.

It is possible that federal legislation penalizing coal use could lead to this result. However, under business-as-usual conditions, this result would occur only if utilities ran into capacity limitations or if the relative price and supply of coal and natural gas changed to the advantage of natural gas. Neither of these situations seems likely. Levels of coal generation under the LowNG scenario appear to be well within the capacity of current coal-fired facilities estimated in Part 2, Section 1. The *Annual Energy Outlook 1997* projects that minemouth prices for western coal, on which Missouri utilities largely depend, will decline by 0.8 percent a year through 2000, then increase by 0.2 percent a year through 2015. Western coal production is projected to grow by 1.4 percent a year.

High Sales Scenarios: Table 11 summarizes the aggregate CO_2 emissions projected by the two CT scenarios. CO_2 emissions under the LowNG scenario grow to about 89 million tons in 2015, a high-CO_2 scenario. The HighNG emissions grow to a maximum of about 82 million tons in 2015, a midlevel CO_2 scenario.

The CT-HighNG scenario projects a 1.9 percent annual growth rate for CO_2 emissions, with only a 3 million ton increase after 2010. Under the HighNG scenario, total CO_2 emissions increase by only 1.3 million tons after 2012.

In contrast, the CT-LowNG scenario projects a 2.2 percent annual growth rate in CO_2 emissions between 1990 and 2015, with a 4.5 million ton increase after 2012.

The LowNG scenario implies an increased utility commitment to coal. Under the scenario, coal consumption climbs steadily, reaching 840 trillion Btus in 2015. The maximum theoretical capacity of Missouri's current coal-fired plants is, at most, about 817 trillion Btus, a level that would be exceeded in 2014. If the practical capacity is lower, the limit would be reached earlier. The LowNG scenario therefore assumes that about 800 megawatts of new coal-fired capacity comes on line by 2011, supplying about 6 billion kWh of total electricity requirements.

In contrast, the HighNG scenario is a mixed-fuel scenario, with the same building of new natural gas capacity that occurs under the AEO HighNG scenario. Under the HighNG scenario, coal consumption increases in all years except 2014 and 2015, but remains well within theoretical capacity. Coal consumption reaches a maximum of 740 trillion Btus in 2013, decreases to 724 trillion Btus in 2014 and increases again to 732 trillion Btus in 2015. Therefore, the construction of new coal-fired plants is not required by this scenario, although the scenario is compatible with the retirement or extensive repowering of old coal plants.

Table 11 - Estimated CO_2 emissions for CT (high sales) scenarios

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

Estimated CO_2 emissions	CT-LowNG	CT-HighNG
1990	51,539	51,539
1996	63,854	63,854
2000	65,895	65,619
2005	73,660	72,459
2010	81,425	78,893
2015	88,621	82,131

Increase over 1990 baseline	CT-LowNG	CT-HighNG
1996	12,315	12,315
2000	14,356	14,081
2005	22,121	20,920
2010	29,887	27,355
2015	37,082	30,592

% increase over 1990 baseline	CT-LowNG	CT-HighNG
1996	23.9%	23.9%
2000	27.9%	27.3%
2005	42.9%	40.6%
2010	58.0%	53.1%
2015	72.0%	59.4%

Section 6: Results of sensitivity analysis

The model developed in this chapter is essentially an accounting model that depends on a number of assumptions and exogenous inputs to generate its results. Each scenario under the model is defined by a combination of two primary factors, the level of electricity sales and level of utility natural gas use. In addition, the model depends on assumptions about coal and natural gas technologies.

The model was specified to be suitable for analyzing the sensitivity of emissions estimates to these factors. Tables 12 and 13 summarize some representative results of this analysis.

Table 12 - Representative results of sensitivity analysis

	Values for Scenario in 2015	Units	Original Scenarios		Increase In-State Sales by 1% of AEO		20% Increase in Export Sales	
			AEO	CT	AEO	CT	AEO	CT
Natural Gas (high)	Total (trillion Btu)	Trillion Btu	96	96	96	96	96	96
In-State Sales	Total (million kWh)	Million kWh	85,626	92,956	86,441	93,771	86,441	93,841
	Sales multiplier		0.0%	0.0%	**1.0%**	**1.0%**	0.0%	0.0%
	Export % of instate		5.0%	5.0%	5.0%	5.0%	**6.0%**	**6.0%**
Heat Rates	New NG	Btu/kWh	9.5000	9.5000	9.5000	9.5000	9.5000	9.5000
	New coal	Btu/kWh	9.4630	9.4630	9.4630	9.4630	9.4630	9.4630
	Old NG	Btu/kWh	12.8875	12.8875	12.8875	12.8875	12.8875	12.8875
	Old Coal	Btu/kWh	10.3729	10.3729	10.3729	10.3729	10.3729	10.3729
LowNG Scenario	CO_2 - total	Thousand tons	80,877	88,621	81,760	89,504	81,760	89,579
	CO_2 - coal	Thousand tons	78,995	87,685	79,877	88,568	79,877	88,643
	CO_2 - natural gas	Thousand tons	1,781	862	1,781	862	1,781	862
	Generated from coal	Million kWh	72,980	81,535	73,796	82,351	73,796	82,421
HighNG scenario	CO_2 - total	Thousand tons	74,224	82,131	75,107	83,013	75,107	83,089
	CO_2 - coal	Thousand tons	68,534	76,468	69,417	77,351	69,417	77,426
	CO_2 - natural gas	Thousand tons	5,589	5,589	5,589	5,589	5,589	5,589
	Generated from coal	Million kWh	63,316	70,646	64,132	71,462	64,132	71,531
CO_2 Growth Rate	Low natural gas		1.82%	2.19%	1.86%	2.23%	1.86%	2.24%
Compared to 1990	High natural gas		1.47%	1.88%	1.52%	1.92%	1.52%	1.93%
CO_2 Change from	Low natural gas	Thousand Tons	0	0	883	883	883	958
Original Scenario	High natural gas	Thousand Tons	0	0	883	883	883	958

Table 13 - Representative results of sensitivity analysis

Values for Scenario in 2015	Units	12% Increase Nat. Gas High Usage AEO	CT	1% Decrease Old Coal Heat Rate AEO	CT	11% Decrease New Coal Heat Rate AEO	CT
Natural gas (high) Total (trillion Btu)	Trillion Btu	**108**	**108**	96	96	96	96
In-State Sales Total (million kWh)	Million kWh	85,626	92,956	85,626	92,956	85,626	92,956
Sales multiplier		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Export % of instate		5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Heat Rates New NG	Btu/kWh	9.5000	9.5000	9.5000	9.5000	9.5000	9.5000
New coal	Btu/kWh	9.4630	9.4630	9.4630	9.4630	**8.4221**	**8.4221**
Old NG	Btu/kWh	12.8875	12.8875	12.8875	12.8875	12.8875	12.8875
Old Coal	Btu/kWh	10.3729	10.3729	**10.2691**	**10.2691**	10.3729	10.3729
LowNG Scenario CO_2 - total	Thousand tons	80,877	88,621	80,087	87,803	80,877	87,969
CO_2 - coal	Thousand tons	78,995	87,685	78,205	86,867	78,995	87,033
CO_2 - natural gas	Thousand tons	1,781	862	1,781	862	1,781	862
Generated from coal	Million kWh	72,980	81,535	72,980	81,535	72,980	81,535
HighNG Scenario CO_2 - total	Thousand tons	73,331	81,237	73,539	81,366	74,224	82,131
CO_2 - coal	Thousand tons	66,970	74,904	67,849	75,703	68,534	76,468
CO_2 - natural gas	Thousand tons	6,259	6,259	5,589	5,589	5,589	5,589
Generated from coal	Million kWh	61,872	69,202	63,316	70,646	63,316	70,646
CO_2 Growth Rate Low natural gas		1.82%	2.19%	1.78%	2.15%	1.82%	2.16%
Compared to 1990 High natural gas		1.42%	1.84%	1.43%	1.84%	1.47%	1.88%
CO_2 Change from Low natural gas	Thousand tons	0	0	(790)	(818)	0	(652)
Original Scenario High natural gas	Thousand tons	(893)	(893)	(685)	(765)	0	0

Columns 2-3: Increases in sales

An identical increase in sales leads to the same increase in projected CO_2 emissions under all scenarios. An increase in export sales of electricity has the same effect as an increase in in-state sales. However, since exports are estimated by default as 5 percent of sales, a 20 percent increase in export sales is required to equal a 1 percent increase in in-state sales.

In the AEO scenario, if in-state sales increase by 1 percent, CO_2 emissions in 2015 increase by about 1.2 percent under the HighNG scenario, versus 1.1 percent under the LowNG scenario. A similar differential between "high" and "low" natural gas occurs in the CT scenarios.

This differential is because the scenarios assume all additional sales "at the margin" will be met by increased generation from coal. Since average tons of CO_2 emissions per kilowatt-hour are initially lower for the HighNG scenarios, the incremental emissions from coal have a higher impact on the HighNG average.

Column 4: Increase in natural gas consumption

A 12 percent change in natural gas consumption under the HighNG scenarios has about the same effect as a 1 percent change in sales. The model assumes that an increase in natural gas generation displaces some generation from coal and therefore reduces total emissions.

Columns 5 and 6: Impact of improved heat rates for coal-fired generation

Coal heat rates were discussed in Part 2, Section 2. A 1 percent reduction in the average heat rate for established coal plants might be a realistic target. The effect on CO_2 emissions would be on the same order of magnitude as a 1 percent reduction in sales or a 12 percent increase in natural gas use.

Column 6 tests sensitivity to the construction of a very advanced new coal-fired plant. This is relevant only to the CT-LowNG scenario, which assumes that the new coal-fired plant(s) to be built will have a lower heat rate (9,463 Btus/kWh heat rate) than the average for current coal-fired plants (10,269 Btus/kWh heat rate).

In its 1995 IRP report, AmerenUE considered very advanced technology, advanced pulverized coal with advanced FGD technology, with an estimated heat rate of 8.442 Btus/kWh. Introduction of the new technology at the scale envisioned in the scenario would have about 80 percent of the impact on total utility CO_2 emissions and would lead to a general improvement in the statewide average heat rate for coal.

Part 3: Summary

Table 14 and Table 15 summarize and compare the AEO-direct, CT-direct and extended estimates of utility CO_2 emissions in 2005 and 2015. The tables also indicate, for each estimate, the percentage increase over 1990 baseline emissions.

Table 14 - Direct and extended scenario estimates of Missouri utility CO_2 emissions in 2005

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	AEO direct estimate	CT direct estimate	CT Sales-LowNG	CT Sales-HighNG	AEO Sales-LowNG	AEO Sales-HighNG
Coal	51,238	72,378	64,693	72,940	70,368	70,329	67,965
Natural Gas	207	768	624	624	1,995	768	1,995
Petroleum	93	13	96	96	96	13	13
Total utility emissions	*51,539*	*73,158*	*65,413*	*73,660*	*72,459*	*71,110*	*69,972*

Increase over 1990 baseline

Coal	41%	26%	42%	37%	37%	33%
Natural Gas	270%	201%	201%	862%	270%	862%
Petroleum	-86%	3%	3%	3%	-86%	-86%
Total	*42%*	*27%*	*43%*	*41%*	*38%*	*36%*

Table 15 - Direct and extended scenario estimates of Missouri utility CO_2 emissions in 2015

Units: 1,000 Short Tons Carbon Dioxide (CO_2)

	1990	AEO direct estimate	CT direct estimate	CT Sales-LowNG	CT Sales-HighNG	AEO Sales-LowNG	AEO Sales-HighNG
Coal	51,238	78,584	72,957	87,685	76,468	78,995	68,534
Natural Gas	207	1,781	862	862	5,589	1,781	5,589
Petroleum	93	102	74	74	74	102	102
Total utility emissions	*51,539*	*80,467*	*73,893*	*88,621*	*82,131*	*80,877*	*74,224*

Increase over 1990 baseline							
Coal		53%	42%	71%	49%	54%	34%
Natural Gas		759%	316%	316%	2595%	759%	2595%
Petroleum		9%	-21%	-21%	-21%	9%	9%
Total		*56%*	*43%*	*72%*	*59%*	*57%*	*44%*

For 2005, with one exception,[43] the differences between estimates are not large. By 2015, however, the estimates have separated into fairly distinct low, midrange and high groups. By that year, the percentage increase over baseline 1990 emissions ranges from 72 percent (CT-LowNG scenario) to 43 percent (CT direct estimate and AEO-HighNG scenarios.)

Under the CT-LowNG scenario, coal is the source of more than 99 percent of all utility CO_2 emissions. Even under the AEO-HighNG scenario, it is the source of 93 percent of emissions. The CT-LowNG scenario involves Missouri utilities in an increased commitment to coal, while the AEO-HighNG scenario is a fuel-switching scenario that implies a move away from coal.

In the middle are three midrange estimates that project 80 to 82 million tons of utility CO_2 emissions in 2015; the AEO direct estimate, CT-HighNG and AEO-LowNG scenarios. The CT-HighNG scenario is a mixed-fuel scenario; the AEO-LowNG scenario is a business-as-usual scenario under conditions of relatively slow electricity sales growth.

Even the low-CO_2 scenarios imply that under business-as-usual conditions, Missouri utility CO_2 emissions in 2015 will exceed 1990 baseline emissions by more than 22 million tons. Under the high-CO_2 scenario, utility CO_2 emissions could exceed the baseline by more than 37 million tons.

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[43] The CT estimate is an exception for methodological reasons. The CT analysis is based on simple regression analysis. The resulting trend line has a fairly steep slope, but its projections for initial years are unrealistically low.